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BEFORE THE ARIZONA CORPORATION COMMISSION

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AZ CORP COMMISSION
DOCKET CONTROL

COMMISSIONERS
KRISTIN K. MAYES, Chairman
GARY PIERCE
PAUL NEWMAN
SANDRA D. KENNEDY
BOB STUMP

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-08-0571 **STAFF'S NOTICE OF FILING DIRECT TESTIMONY**

The Utilities Division of the Arizona Corporation Commission ("Staff") hereby files the Direct Testimony of Staff Witnesses Dr. Thomas H. Fish, David C. Parcell, Rita R. Beale (Public Version), Corky Hanson, Juan C. Manrique, and Robert G. Gray in the above-referenced matter.

A confidential version of Rita R. Beale's Direct Testimony has also been provided under seal to the Commissioners, their Assistants, the assigned Administrative Law Judge, and the parties that have signed the Protective Agreement in this case.

RESPECTFULLY SUBMITTED this 8th day of June, 2009.

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TESTIMONY

OF

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JUAN C. MANRIQUE

ROBERT G. GRAY

DOCKET NO. G-04204A-08-0571

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA

JUNE 08, 2009

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. G-04204A-08-0571

DIRECT

TESTIMONY

OF

THOMAS FISH

ON BEHALF OF

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 08, 2009

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Schedules
Accompanying the Direct Testimony of Thomas H. Fish, Ph.D.

Schedule	**Description**
THF-1	Attachment 1 – Resume of Thomas H. Fish, Ph.D.
THF-2	Attachment 2 – Revenue Requirement/Rate Design Schedules
	Revenue Requirement
THF – A1	Revenue Deficiency
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THF – B3	Adjusted Test Year RCND Rate Base
THF – B4	Comparative RCND Studies
THF – B5	Post Test Year Non Revenue Producing PIS
THF – B6	Customer Advances
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THF – B8	Purchased Gas Lag
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THF – C6	Rate Case Revenue
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THF - C.16	Payroll Tax
THF - C.17	Rate Case Expense
	COS/Rate Design
THF – RD1	Customer Class Risk
THF – RD2	Summary of Revenues by Customer Class
THF – RD3	Summary of Revenues by Rate Schedule
THF – RD4	Summary of Staff Recommended Rate Design
THF – RD5	Proof of Revenue
THF – RD6	Bill Comparison

EXECUTIVE SUMMARY
UNS GAS INC.
DOCKET NO. G-04204A-08-0571

Based upon my review of the Company's filing and its books and records, I have determined that the Company has an operating income deficiency of $2,077,601 and I recommend that the Company be authorized a base rate increase of $3,395,423. This is based on an original cost rate base of $178,509,369, RCND rate base of $324,538,937, and fair value rate base of $251,524,153. The proposed rates are designed to provide the Company the opportunity to recover its cost of providing service.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Thomas H. Fish. I am President of Ariadair Economics Group. My business address is 1020 Fredericksburg Rd., Excelsior Springs, MO 64024.

Q. What does Ariadair Economics Group do?

A. Ariadair Economics Group provides expert witness and consulting services in administrative and judicial litigation proceedings.

Q. Please describe your educational background.

A. I hold a B.A. (1968) degree in Economics from University of Missouri at Kansas City, a M.A. (1970) degree in Economics from Central Missouri State University, and a Ph.D. (1972) degree in Economics, with minor areas of study in Finance and Marketing, from University of Arkansas.

Q. Please describe your professional experience.

A. I have provided expert witness and consulting services in Economics, Finance, Utility Regulation, Industrial Organization, and related areas in administrative and judicial litigation proceedings for over thirty years. I have also taught graduate and undergraduate college classes in Economics, Finance, Quantitative Methods, Financial Accounting, Managerial Accounting, Cost Accounting, Management and related classes. My resume is attached as Attachment THF – 1.

Q. What is the purpose of your testimony in this case?

A. I have been retained by the Utilities Division of the Arizona Corporation Commission ("Staff") to review the rate application of UNS Gas, Inc. ("Company" or "UNS Gas") and to address the following issues: Revenue Requirement and certain adjustments to Revenue Requirement, Original Cost, Reconstruction Cost New, and Fair Value Rate Base, Cost of Service, Customer Class Risk and Rate Design. I have performed an analysis and evaluation of those issues and will make recommendations regarding them.

Q. Have you reviewed the Company's application for rate relief?

A. Yes. I have reviewed, analyzed and evaluated the Company's application, its rate base and revenue pro forma adjustments, its work papers in support of its pro forma adjustments, and its response to a series of data requests submitted by Staff.

Q. Have you reached any conclusions as a result of your review?

A. Yes.

Q. Have you prepared Schedules in support of your testimony?

A. Yes, I have prepared an attachment, Attachment THF-2, consisting of several Schedules, identified as Schedules THF – A1 through THF – RD6 in support of my testimony. The A, B, and C Schedules are associated with the revenue requirement part of my testimony and the RD Schedules are associated with the Cost of Service/Rate Design part of my testimony.

Q. Would you please describe the A Schedules?

A. Yes. The A Schedules present a summary of the Company's revenue deficiency and gross-up factor. Schedule THF – A1 shows the Company's and Staff's Original Cost Rate Base, Reconstruction Cost New Rate Base, and Fair Value Rate Base and the required operating revenue necessary for the Company to recover its prudent costs of providing service including a fair return on capital. These Staff values are based on the values presented in the B and C Schedules.

Q. Would you explain the three different rate base values that you identify?

A. Yes. The Original Cost Rate Base is the net value of the plant and equipment used and useful in providing natural gas distribution services by the Company. It is measured in dollars actually invested in net plant and equipment. Reconstructed Cost New Depreciated Rate Base is the estimated net value (cost) of the Company's Original Cost Rate Base if that Rate Base had to be reconstructed using the value of today's dollars. The Fair Value Rate Base is the average of the Original Cost Rate Base and Reconstructed Cost New Depreciated Rate Base. The Commission has adopted this procedure for deriving Fair Value Rate Base in other regulatory proceedings.

Q. Please describe the B Schedules.

A. Schedule THF – B1 summarizes the Company's proposed rate base modified to reflect the pro forma adjustments recommended by Staff. Schedule THF-B2 provides a summary of rate base pro forma adjustments. Schedules THF – B3 through THF – B10 are schedules supporting individual pro forma adjustments to rate base. I am sponsoring these Staff adjustments.

Q. Please describe the C Schedules.

A. The C Schedules present a summary of the Company and Staff's Operating Income in Schedule THF – C1, a summary of pro forma income and expense adjustments in Schedule THF – C2, and the remaining C Schedules present support for each of the pro forma adjustments to income or expenses. I am sponsoring these Staff adjustments.

Q. Please describe the RD Schedules.

A. The RD Schedules present support for Staff's Rate Design proposals in this proceeding. Schedule THF – RD1 presents the results of a customer class risk study. Schedule THF-RD2 shows a summary of revenues by customer class and adjusted present rates and proposed rates. Schedule THF – RD3 presents a summary of revenues by rate schedule by adjusted present rates and proposed rates. Schedule THF – RD4 is a summary of Staff recommended Rate Design. Schedule THF – RD5 provides proof of revenue of Staff's proposed rate design. Schedule THF – RD6 provides a bill comparison of present and Staff proposed rates.

Q. Were these Schedules prepared by you or under your supervision?

A. Yes.

REVENUE REQUIREMENT

Q. What revenue increase has UNS Gas requested?

A. UNS Gas requested an increase in revenues of $9,480,876 or about a 6 percent increase to a customer's total bill compared to test year revenue, inclusive of gas costs. According to Company Witness David G. Hutchens the reason for the requested increase is the Company's inability to recover its costs, growth in its service territory, the related increase in capital expenditures and operating costs, as well as increases related to rising material and labor costs.

Q. What does Mr. Hutchens project the number of UNS Gas customers to increase by?

A. On Page 3 of his testimony Mr. Hutchens states that, at the end of the June 30, 2008 Test Year, UNS Gas had a customer base of 145,000 and projected that the number of UNS Gas customers will increase by, on average, 2.5 percent annually.

Q. What revenue increase does Staff recommend?

A. Staff is recommending an increase in gross revenue requirement of $3,395,423 or 2.1 percent over test year including cost of gas.

ADJUSTMENTS TO RATE BASE

Test Year

Q. What test year did the Company use?

A. The Company used a historic test year ending June 30, 2008.

Q. Would you explain the concept of test year?

A. Yes. Regulated utilities such as UNS Gas have the opportunity to recover their prudently incurred cost of providing service, including an opportunity to recover their capital cost. Rates for utility services are set by utility regulators, in this case the Arizona Corporation Commission, so that utilities have an opportunity to recover these prudent costs incurred in the provision of service.

Q. How are prudently incurred cost of providing service determined?

A. The prudently incurred cost of providing service is determined on the basis of a test year. A test year reflects a level of operating revenues and expenses and net plant investment that is representative of normal conditions that are expected to exist when the resulting rates are in effect.

Q. What is required to determine the proper, or representative, level of expense, revenues, and investment?

A. In order to determine the proper, or representative, level of expense, revenues and investment, individual items may be adjusted to reflect their value on an on-going basis.

Some rate base items such as plant in service and accumulated depreciation are based on end of test year levels. Other rate base items such as materials and supplies are based on a test year average level. Certain expense items such as payroll and payroll tax expense are annualized. Expense items that have been incurred, but are not necessary for the provision of service, are removed from the test year. In addition, some expense items, such as legal expense, may occur on ongoing but irregular intervals and require adjusting to normal levels. So some items may require no adjustments, some may require removal, some may require annualization and some may require normalization. After all these adjustments have been made, test year revenue is compared to test year required revenue and, if a shortfall exists, rates are set to provide the utility the opportunity to recover its cost of providing service.

Q. What is the importance of the test year concept and the adjustment process you described above?

A. The adjusting process applied to test year values described above, when conducted properly, will remove (eliminate) all unnecessary transactions, convert possibly erratic and variable transactions to "normal" (normalize) values, and annualize intra-year growth or decay in ongoing values. The result will be a test year that represents the best determination of what the Company's actual net investment in plant and equipment is, what its ongoing expenses can reasonably be expected to be, and what its ongoing income can be expected to be. The Company has the opportunity to recover its prudent expenses of providing service, and these are identified through the adjusting process. It also has the opportunity to recover its prudent capital cost incurred in the provision of service. This is typically done by applying its Weighted Average Cost of Capital ("WACC") to its net rate base. The WACC is calculated by adding the cost of each capital component (debt, common equity, preferred stock, etc.,) times the proportion of each capital component to the total capital structure together. Adding the Company's expenses to its Capital Cost results in a determination of the Company's revenue requirement. By comparing its revenue requirement with its test year income, a determination is made as to what, if any, revenue deficiency the Company is experiencing. The final step is to design rates so that the new rates for each customer class times the number of customers in each customer class totals the revenue requirement for the test year.

RATE BASE

Q. Are you proposing pro forma adjustments to rate base?

A. Yes. I am proposing four pro forma adjustments to original cost and Reconstructed Cost New Depreciated ("RCND") rate base. These proforma adjustments to rate are: 1) Post Test Year Non-Revenue Plant in Service; 2) Customer Advances Adjustment; 3) Working Capital; and 4) Accumulated Deferred Income Tax ("ADIT"). In addition to these pro forma rate base adjustments I present the results of an analysis and evaluation of the Company's RCND study.

RCND Test Year Calculation Inconsistencies

Q. What is a RCND rate Base?

A. A RCND Rate Base" is defined in A.A.C R14-2-103 as: "An amount consisting of the depreciated reconstruction cost new of the property (exclusive of contributions and/or advances in aid of construction) at the end of the test year, used and useful, plus a proper allowance for working capital and including all applicable pro forma adjustments. Contributions and advances in aid of construction, if recorded in the accounts of the public service corporation, shall be increased to a reconstruction new basis."

Q. Would you provide an overview of the process of deriving a RCND rate base?

A. Yes. A RCND study is a point in time measurement, just as an original cost rate base is a point in time measurement. That is, the Company's RCND rate base today most likely will not have the same value as the RCND rate base as of June 30, 2008. Rate Base is a balance sheet idea and balance sheet values are point in time measurements while Income Statement measurements are over time, or flow measurements.

Q What information does the RCN and RCND Rate Base convey?

A The reconstruction cost new ("RCN") rate base provides the gross value of the rate base expressed in today's dollars, and the RCND rate base provides the net value of the rate base expressed in today's dollars. A properly constructed RCND rate base provides an estimate of what the cost would be to reconstruct the existing rate base if it were to be constructed now in today's dollars.

Q. Are there underlying assumptions of RCND studies?

A. Yes. An underlying assumption of RCND studies is that the value of a dollar today, everything else being equal, has more value than a dollar to be received in the future and that a dollar received in the past, everything else being equal, has more value than a dollar to be received now. So the RCND rate base is the value of the rate base when all net dollars invested have the same value regardless of when they were invested. The Original Cost rate base is the value of the rate base when all net dollars have the specific value of those dollars at the time they were spent, that is, they are not adjusted for changes in the value of the dollars. The way to convert current dollars into constant (value) dollars is to create a price (or cost) index for the various types of investments and use the price (or cost) index to convert to constant dollars.

Q. What is a price, or cost, index?

A. Index values provide a relative comparison of prices or costs over time. Price or cost indices have a base period where the index value is 100 and observations away from the base have different values based upon the value of the dollars at those observations. For the RCND rate base derivation we want the base period to be the test year. That is, we want to conduct the analysis in today's dollars because the RCND will show us how much we would have to spend, in today's dollars, to duplicate the original cost rate base. The primary source of index values used in RCND calculations is the Handy-Whitman construction cost index by geographic location and Federal Energy Regulatory Commission ("FERC") account.

Q. Please describe the Handy-Whitman cost indices.

A. The Handy-Whitman indices are index values of plant and equipment costs by FERC account and by region. They have a base value (100) early on in the time series so we need to convert the base from the earlier base period of the series to the end of test year observation. This conversion process is one of dividing the end of test year index by each individual index throughout the series.

Q. Can you give an example of this?

A. Yes. Consider the following example where we are converting the base period from year one in the original index to year four in a new index:

Year	Original index value	Conversion equation	New Index value
1	100.00	(130/100)*100	130.00
2	110.00	(130/110)*100	118.18
3	120.00	(130/120)*100	108.33
4	130.00	(130/130)*100	100.00

Note that the New Index value series has the same relative values between the years as does the Original index value series. However, the indices are measured with respect to year 4 values rather than with respect to year 1 values. The conversion of the base period demonstrated above shown under the column headed "New Index Value" corresponds to the Company's term "Trend Value" used in its RCN study.

This process is simply one of changing the base period but not the relative values of the observations between periods. In the example above, the base period was changed from year one to year four.

Q. Are there any unusual characteristics about values calculated using this technique?

A. Yes. By definition, the RCND values for the test year will be the same as the Original Cost values for the test year.

Q. Can you please briefly explain the difference?

A. Yes. The base period always has an index value of 100 which means that current and constant dollars are the same and the base period for RCND studies for regulatory purposes is the test year. This equality that exists in the base period will only occur at the base period unless the index values for previous, (or subsequent) periods are exactly equal to the original index value. This will rarely, if ever, be the case.

Q. Does this feature of the construction of RCND rate base have implications for determining the validity of the resulting RCND rate base?

A. Yes. If a proforma adjustment to the Original Cost rate base and the corresponding pro forma adjustment to the RCND rate base for an expenditure during the test year have different values, then there was an inconsistency in constructing the RCND rate base.

Q. Please briefly explain the Company's position.

A. Post Test Year Non-Revenue Plant in Service is defined by Mr. Dukes as ". . . investments made prior to the end [but presumably within the test year] of the test year into plant that will not produce additional revenues beyond the test year adjusted amount. These investments were not in service by the end of the test year, but will be in service when rates established in this case go into effect. These are investments in items like transportation equipment, general plant, replacements and relocations of existing facilities." (testimony page 11, lines 5 – 10). So, the investment is clearly not made prior to the test year. The Original Cost rate base pro forma adjustment made by Mr. Dukes for this item is $1,527,588 but the RCND rate base pro forma adjustment made by Mr. Dukes is $2,514,427. The pro forma RCND adjustment is 64.6 percent larger than the pro forma Original Cost adjustment which indicates that an inconsistency was made in constructing the RCND rate base unless a large amount of the investment was made prior to the test year.

Q. Did you evaluate the Company's RCND studies for the 2005 test year and the test year ending June 30, 2008?

A. Yes, I did.

Q. What is the result of your analysis?

A. I noticed that the Handy-Whitman Indices between 2005 and 2008 had barely changed,[1] and that suggests that the major source of change in both the Original Cost and RCND rate bases were from net investments during that period of time. Therefore, the ratio of test year 2005 Original Cost to RCND rate bases should be close to the ratio of June 30, 2008 Original Cost to RCND rate bases. As shown in Schedule THF – B3, the ratios are skewed. The ratio of RCND to Original Cost rate base in test year ending 2005 was 134.1 percent but in test year ending June 30, 2008 the ratio was 176.3 percent. The other ratios shown in Schedule THF – B3 show similar skewed results.

Q. What does this indicate to you?

A. It indicates that inconsistencies were made in conducting the studies.

Q. Did you determine where the inconsistencies were made and what they were?

A. Yes. Inconsistencies were made in both studies. The inconsistencies occurred because the data necessary to perform the studies were not available. Therefore neither study provides the Commission with known and measurable RCND rate base values. Since the fair value rate base is the average of the original cost rate base and the reconstructed cost new rate base, the fair value rate base, like the RCND rate base, is not known and measurable.

An inconsistency was also made in the earlier study when the Company used an incorrect con-version factor index of 435 to calculate its "trend value" FERC account 276, mains. It should have used the 2005 index value of 556.

[1] See Company response to Staff data request 6.1.

Q. Do you have additional support for your determination that the RCND studies are incorrect?

A. Yes. Company Witness Dukes explained that when Citizens' gas assets were acquired by UniSource Inc. the detailed continuing property records of Citizens' gas assets, located in New Orleans, were not available. Also, Arizona law requires that RCND studies must be filed with the application when a regulated Arizona utility files a request for rate relief. In the case of UNS Gas, since the detailed information required for a known and measurable determination of reconstruction cost new rate base was not available when it filed its last rate case, the Company took an extremely conservative approach in deriving its RCND rate base. It did this in its last rate case and kept the value of the RCN down so as not to overstate the RCND rate base value.

Q. Can you show how the Company did this?

A. Yes. Schedule THF-B4 reproduces portions of the Company's work papers associated with the RCND study ending December 31, 2006 and the RCND Study ending June 30, 2008. Column A shows the Handy-Whitman cost index for FERC 276, mains, used by the Company in its December 31, 2006 RCND Study. For the 2005 study, the column is headed "Handy-Whitman line 43, which indicates cast iron mains, but the values in the column are from line 44, steel mains. Note the shaded value 435. This is the cost index for 2004, not 2005. The actual value for 2005 is 556. Columns B and C show the trend values for 1998 through 2005 using the correct and the incorrect cost indices. The correct cost index value is 27.8 percent higher than the value calculated, this is shown in Column D. Column G shows the relative value of the '08 study compared to the '05 study. The '08 values are less than 2 percent greater than the '05 values, if the '05 values had used the correct '05 cost index rather than the '04 index, not the 50 percent plus values represented by the Company in its studies as shown in Schedule THF – B3.

The Handy-Whitman has three indices for FERC account 276, mains. These indices are for cast iron mains, steel mains, and plastic mains. The Company, however, did not have the necessary data that would allow it to use the correct indices and corresponding correct FERC account values. Therefore, it selected the FERC 276 index which had the smallest impact on the study.

Q. Did you conduct a RCND study that corrected for the Company's inconsistencies?

A. No. If I, or any other analyst, attempted to conduct a RCND study using the Company's data, the result would be the same. Without the information regarding the detail of the Company's system, the resulting values could not be considered known and measurable.

Q. What are your recommendations regarding the inconsistencies you found in the Company's RCND study?

A. I recommend that the Commission adopt the RCND study as filed by the Company for this proceeding. The difficulty with the study results from the unavailability of historical detailed Continuing Property Records when Citizens assets were acquired. Over time the impact of the gaps in the older data will diminish and the indices associated with the composition of mains, and other related problems, will tend to go away.

Post Test Year Non-Revenue Producing Plant

Q. Are you proposing a pro forma adjustment to the Company's proposed rate base for Test Year Non-Revenue Producing Plant?

A. Yes.

Q. What pro forma adjustment for Post Test Year Non-Revenue Plant did the Company propose?

A. The Company proposed to increase test year original cost rate base by $1,527, 588 and, as discussed above, increase the RCND rate base by $2,514,427.

Q. What was the reason given by the Company for this pro forma adjustment?

A. According to Company Witness Dallas Dukes:

> "The Commission should allow UNS Gas to recover such costs. The Company has made investments to serve existing customers and will not see any additional revenue directly related to these investments until the time the investments are reflected in rate base within a rate proceeding. The inclusion of post test year non-revenue producing plant in rate base will help the Company to begin recovering its investment and an opportunity at earning a reasonable return in a more equitable time frame. If this current case follows an expected course, new rates will go into effect in December 2009 at the earliest. Based upon the circumstances of this matter in which Staff required at least six months of actual rates billed within the test year – a new rate case could not be filed until October of 2010, with rates most likely not effective until January 2012. So the recovery of and on investments actually made prior to the end of the test year, but not technically in service, will not produce additional revenues until January 2012, in other words, over 3 1/2 years after the investments were made to serve existing customers. (Dukes Direct Testimony, page 11, lines 14 – 26.)

Q. Do you agree with Mr. Dukes' justification for inclusion of Post Test Year Non-Revenue Plant in Rate Base?

A. No. Presumably, the investment was made in order to increase the Company's efficiency/productivity and hence reduce costs of providing service such as maintenance cost. This could result in a mismatch between post-test year revenue and costs. In addition, the Company has a choice as to when it files an application for rate relief. The Company could have waited to file its application so as to include this investment in its test year.

Q. Do you know when the Company made the investments in Post Test Year Non-Revenue Producing Plant in Service it wishes to include in rate base?

A. No. The Company did not provide this information in response to data requests or as part of its work papers in support of its pro forma adjustments.

Customer Advances Adjustment

Q. Are you proposing a pro forma adjustment to the Company's proposed pro forma adjustment to rate base for Customer Advances?

A. Yes.

Q. What pro forma adjustment for Customer Advances did the Company propose?

A. The Company is proposing that the test year reduction to rate base for Customer Advances be "about $600,000."

Q. What is the Company's justification for this pro forma adjustment?

A. Mr. Dukes, page 12, lines 4 – 19, suggests that approximately $600,000 of customer advances have already been spent on projects not included in rate base and the Company, therefore, does not have those funds available to spend. In addition, since those projects are not reflected in rate base and the contributed capital for those investments is no longer available, the Company's opportunity to earn a reasonable return is reduced by such treatment.

Q. Do you agree with the Company's argument in favor of including $600,000 of customer advances in rate base?

A. No.

Q. Is it your understanding that Arizona utilities have the option to include customer advances in rate base?

A. No.

Working Capital

Q. Are you proposing a pro forma adjustment for Working Capital?

A. Yes.

Q. What are the components of Working Capital?

A. Working Capital is composed of Materials and Supplies, Prepayments, and Cash Working Capital.

Q. Are you proposing any adjustments in these Working Capital components?

A. I am proposing an adjustment only to cash working capital.

Q. What is the basis for your adjustment to Cash Working capital?

A. The Company conducted a lead-lag study to determine its cash working capital requirements. The lead-lag study measures the timing differential between accounts receivable and accounts payable and weights this differential by dollars. My analysis and evaluation of the Company's study suggested that they may have erred in determining lag days for payment of purchased gas. They used 27.89 days for their purchased gas payment lag. However, this included what appears to be an abnormal pay structure for the months of December 2007, January 2008 and February 2008. Payment averaged only 17.83 days for these months, not the normal 35 days. The impact of this early payment appears to have served to shorten the lag period to 27.89 days. Adjusting the Company's analysis for this correction has a significant impact on the Company's cash working capital requirements. This results in an adjustment to working capital requirements of $(1,624,840).

Q. Did you prepare Schedules to support this adjustment?

A. Yes. Schedules THF – 7, THF – B8 and THF – B10 address this issue. Schedule THF – B10 shows the modifications required to the Company's lead lag study to reflect this payments change for natural gas purchases as well as other adjustments required due to this modification. Schedule THF – B8 presents a summary of purchased gas payments lags, and Schedule THF – B7 presents the results of working capital net change.

Accumulated deferred Income Tax ("ADIT")

Q. Are you proposing a pro forma adjustment for Accumulated Deferred Income Tax?

A. Yes.

Q. What is your proposed adjustment?

A. The adjustment to Accumulated Deferred Income Tax is required because of the proforma adjustment to eliminate the Supplemental Executive Retirement Program ("SERP") expense effects income tax. The SERP proforma adjustment is discussed below in the revenue requirements pro forma adjustments discussion.

Q. What is your pro forma adjustment for ADIT?

A. $38,994.

Q. Did you prepare a Schedule in support of this pro forma adjustment?

A. Yes. Schedule THF – B9 shows the calculations required for this pro forma adjustment.

ADJUSTMENTS TO OPERATING INCOME

Q. Do you provide Schedules summarizing your pro forma adjustments to operating income?

A. Yes. Schedule THF – C1 provides a summary of Adjusted Net Operating Income and Schedule THF – C2 provides a summary of pro forma Income Statement Adjustments. The sections below provide a discussion of each of the pro forma adjustments to Operating Income.

Customer Annualization

Q. Did the Company propose a pro forma Customer Annualization adjustment?

A. Yes. The Company proposed a reduction in income of $516,003 to represent its test year reduction in customers. From a review of the work papers associated with the Company's Customer Annualization adjustment, it appears that $302,550 of this amount arises directly from the Customer Annualization adjustment and the remainder appears to be the adjusted amount from the large industrial customer.

Q. Do you agree with the pro forma Customer Annualization adjustment recommended by the Company?

A. No. Mr. Erdwurm sponsors the pro forma Customer Annualization adjustment using the June, 2008 values. He states on Page 7, lines 5 –9, that "Customer Annualization adjustments should restate the number of test-year bills and volumes to be consistent with (but not necessarily equal to) the number of customers on the system at the end of the test year. Customers should expect a positive customer adjustment on a growing system. A positive customer adjustment typically entails additions to both customers and therms."

Here he appears to recognize that his annualization results are not normal or representative of a test year. He goes on to say, page 8, lines 1 –20, that the Company is experiencing "cyclical, seasonal" fluctuations and customer counts in the summer months tend to be less than in other times of the year. So, if the Commission had adopted the Company's annualization in its last rate case, then the annualization adjustment would have been consistent with year end levels. Essentially, Mr. Erdwurm seems to be saying that a Customer Annualization adjustment based on calendar year end customer levels is more indicative of the Company's actual experience because of a normal summer decline in the number of customers.

Q. Do you agree with Mr. Erdwurm that an end of calendar year Customer Annualization adjustment could be a better representation of ongoing customer and usage levels than a summer month adjustment?

A. Yes.

Q. Do you agree with Mr. Erdwurm's implied recommendation of a "cyclical, seasonal" Customer Annualization procedure?

A. No. The cycle time series component is defined as a wave like fluctuation about the trend with no predictable phase or amplitude, i.e., duration or severity. So attempting to make an annualization adjustment based on the time series cycle component would not work precisely because the cycle component is not predictable and thus not regularly recurring. The seasonal component of a time series, however, is defined as a regularly recurring fluctuation about the trend with predictable phase and amplitude. So it should be possible to determine if there is a seasonal component to the time series of customer counts and usage by customer class and to make adjustments which, in conjunction with the Commission's customary procedure for making annualization adjustments, would be representative of the Company's usage patterns.

As Company Witness Erdwurm suggests, it would be possible to identify a seasonal/cyclical time series component. However, if one were to attempt that then the unpredictable nature of the cyclical component would corrupt the predictable seasonal component so that the resulting value could not be expected to successfully derive a Customer Annualization adjustment.

Q. Did you make a pro forma Customer Annualization adjustment?

A. Yes. My Customer Annualization adjustment calculations are presented in Schedules THF – C3 and THF – C4. I followed Mr. Erdwurm's suggestion that end of calendar year values would be more appropriate than end of test year values for Customer Annualization purposes. Therefore, I based my calculation on December 2007 customer values. Since this is the mid-point (end of December 2007) of the test year, I used Mr. Hutchens' growth factor of 2.5 percent per year and adjusted the mid-year customer count by 1.25 percent.

THF – C3 presents a summary of the adjustment and THF – C4 presents the details of the calculations. The Excel model used as the basis for THF – C4 is the Company annualization model with my end of period and growth adjustments replacing the Company's assumed values in the model. My calculations result in an adjustment of $869,221 as compared to the Company's adjustment of negative $302,550 (total of $516,003).

Weather Normalization

Q. Did you propose a Weather Normalization adjustment?

A. Yes. My Customer Annualization adjustment resulted in an increase in the number of customers for the test year. Since the test year was cooler than normal, these additional customers could be expected to consume more natural gas than in a normal year. Schedule THF – C5 shows that the Weather Normalization adjustment based on my Customer Annualization pro forma adjustment results in a weather normalization pro forma adjustment of -$903,890 compared to the Company's weather normalization pro forma adjustment of -$882,454. The net change that I am proposing is -$21,436.

Rate Case Revenue Annualization

Q. What is Rate Case Revenue Annualization?

A. The Rates ordered by the Commission in the Company's last rate case went into effect on December 1, 2007. The previous rates were in effect until December 1, 2007 so the new rates required annualization to reflect revenue they would have generated had they been in effect for the entire test year.

Q. Did the Company propose a pro forma adjustment representing Rate Case Revenue Annualization?

A. Yes. The Company proposed increasing annualized revenue by $1,448,476.

Q. Did you propose a pro forma adjustment representing Rate Case Revenue Annualization?

A. Yes. My Customer Annualization adjustment increased the number of test year customers; therefore, more customers would have paid the lower rates in effect prior to December 1, 2007. My proforma adjustment is presented in Schedule THF – C6 and increases the proposed Company increase in revenue for this adjustment by $349,038.

Bad Debt Expense

Q. Did you make an adjustment to the Company's proposed bad debt expense?

A. Yes. Schedule THF – C7 presents the calculations for my bad debt adjustment of negative $186,627.

Q. How is bad debt expense treated?

A. Bad debt is handled in a two part process. Actual losses are reviewed and an estimate of the expected loss is calculated. An accrual for that expected loss is booked. The actual losses are booked to those accruals.

Q. What has the Company's bad debt expense been over the last few years?

A. The actual bad debt expense experienced by the Company is as follows: 2006 - $972,007, 2007 - $668,482, 2008 - $849,695, and test year - $625,168.[2]

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[2] Company response to Staff data request THF 8.12.

Q. What was the Company's Allowance for Doubtful Accounts for the years 2006, 2007, and test year end June 30, 2008?

A. Company Schedule E-1, line 13 shows that Allowance for Doubtful Accounts increased from $(366,736) in 2006, to $(1,010,624) in 2007, to $(1,219,587) at test year end June 30, 2008. This is an increase of 322.55 percent over that period.

Q. What do you determine from this increase in Allowance for Doubtful Accounts over that time period?

A. The Company is over accruing its Allowance for Doubtful Accounts.

Q. What is your recommendation?

A. I recommend that the Company's Uncollectibles rate be reduced from its 0.487 percent to 0.3468 percent until the accrual of bad debts becomes aligned with the Company's bad debt experience. At this Uncollectibles rate, the Company can expect to reduce its Allowance for Doubtful Accounts to the current Uncollectibles per Company amount of $688,379 in three years. That would provide the Company a 100 percent safety balance and it could then increase its Uncollectibles rate to its actual experience.

Fleet Fuel Expense

Q. Please explain your Fleet Fuel Expense Adjustment.

A. The Fleet Fuel Expense Adjustment is presented in Schedule THF – C8. The Company experienced average price per gallon for fuel of $3.35 during its test year, with total miles of 2,960,186 and total gallons of 222,973. The Energy Information Administration projects average fuel cost to be $1.96 for 2009. In light of the significant decline in fuel cost, I am proposing a fleet fuel expense reduction of $294,599.

Postage Expense Adjustment

Q. Please explain your Postage Expense Adjustment.

A. The Post Office announced a two cent increase in first class postage rates after the Company had filed its application. This increase is known and measurable and should be included as a test year expense. Schedule THF – C9 shows the calculation of the increase in test year postage expenses of $49,594. The Schedule shows the increase in postage for the test year customers counted by the Company plus the additional postage for the additional test year customers that resulted from my Customer Annualization pro forma adjustment.

Membership and Industry Association Dues

Q. Please explain your Membership and Industry Association Dues adjustment.

A. In its last rate case the Commission in Decision No. 70011 disallowed 3.511 percent ($1,523) associated with marketing and lobbying activities (pages 32-33). The Company agreed to this disallowance. I am proposing the same pro forma adjustment of 3.511 percent. This is shown in Schedule THF – C10.

Q. Does the Company describe an array of valuable services provided to the Company via its membership in American Gas Association ("AGA")?

A. Yes. Company Witness Smith describes many benefits he ascribes to AGA membership.

Q. Should these benefits outweigh the relatively small marketing and lobbying activities cost?

A. No. The Company has not demonstrated that AGA membership is necessary for the provision of service to its customers.

Legal Expense Adjustment

Q. Are you proposing a pro forma adjustment to legal expenses?

A. Yes. The Company made a pro forma adjustment of $305,984 and my pro forma adjustment removes the Company adjustment. This is shown in Schedule THF – C11.

Q. What was the basis for the Company's pro forma legal expense adjustment?

A. According to Company Witness Dukes, the test year contained $310,000 in outside legal costs related to the last UNS Gas rate case filing that disallowed recovery and was written off within the test year. He says that once that amount is removed the Company only has $84,000 left and that is not indicative of an ongoing level of legal expenses.

Q. Do you agree that the Company's procedure was correct for removing the legal expenses associated with the last rate case?

A. No. The Company accrued legal expenses associated with its last rate case well after the date of Decision No. 70011. Therefore, this Company adjustment should be removed.

Call Center pro forma Adjustment

Q. Please explain the Call Center expense.

A. The total test year call center charge to UNS Gas was $1,399,522, which averages $116,627 per month. In the last rate case, the Company had increased its monthly call center costs from $17,636 to $76,227 and requested it be allowed to recover this amount because the consolidated call center provided a higher level of service to customers. In addition, the Company said the Call Center could handle increased call traffic (which had nearly doubled), expanded service hours, and provided one number service for gas and electric customers in Mohave and Santa Cruz counties. The Commission allowed the Company to recover the increased costs in its rates.

Since the last rate case, the average monthly cost has increased from $76,227 to $116,627 and, rather than doubling, the number of service orders per month has declined from 5,435 in 2006 to 4,646 in 2008. I present my call center pro forma adjustment in Schedule THF – C12. I am recommending that the Commission disallow the increase of $484,798 because the number of service calls has decreased and yet call center costs have increased by 53% since the last rate case. Unless the Company can show that the increased call center expense resulted in savings elsewhere, and that customers have benefited by this increase in cost, the Commission should not permit this increase.

Interest Synchronization Adjustment

Q. What is interest synchronization?

A. The test year income tax expense is affected by application of the weighted cost of debt to rate base. Since my rate base is different than the Company's the interest amount will also be different. This results in an adjustment to the amount of interest included in the tax calculation. Schedule THF – C13 shows my calculations. I have increased income tax by $54,906 to reflect this impact.

Incentive Compensation and Exec. Comp/Benefits Pro Forma Adjustment

Q. Please explain your proforma adjustments for incentive compensation and Executive Compensation/Benefits.

A. In its last rate case the Commission disallowed certain incentive compensation and Supplemental Executive Retirement expenses. For various reasons the Commission decided to disallow 50 percent of certain incentive program costs and all Supplemental Executive Retirement Plan costs. The Commission, in its Decision No. 70011 stated "Implicit in the Company's argument is the concept that 'if we don't recover fully what we believe are our reasonable costs in our preferred manner, we'll simply shift those costs to another account to disguise the costs and ultimately ensure recovery.' " (Page 28, Lines 20 – 23)

The Company may have behaved in just the manner suggested by the Commission. The total incentive compensation and executive compensation/benefits increased by almost 15 percent between 2007 and 2008, but individual programs seem to have evolved considerably since the last rate case. I recommend that the Company share the incentive compensation expenses with the owners of the Company for PEP related incentive compensation. The PEP pro forma adjustment is shown in Schedule THF – C14 and is one half of the total PEP costs, or $117,394.

Schedule THF – C15 shows the pro forma adjustment for SERP related expenses. I am recommending that the Commission disallow $310,412 of SERP related expenses in this proceeding. The Company identified this SERP related expense amount in its lead lag study.

Payroll Tax Expense Adjustment

Q. Please explain your payroll tax expense adjustment.

A. The Payroll Tax Expense is related to the PEP incentive pay adjustment. Schedule THF – C16 show this pro forma adjustment. I estimated payroll tax expense to be 10 percent of the PEP incentive allowance. This is slightly higher than the social security and Medicare percentages but lower than total benefits.

Rate Case Expense Adjustment

Q. Please explain your Rate Case Expense pro forma Adjustment.

A. This is an adjustment provided by the Company in its response to Data Request 6.88 and is reproduced as THF – C17. It removes the test year amortization of rate case expense of $300,000 allowed in Decision No. 70011 for the 2006 rate case that will be recovered prior to new rates becoming effective. The adjustment results in a reduction of test year expense of $58,333.

Income Tax Adjustment

Q. Please explain your income tax adjustment.

A. This adjustment is shown on page 4 of Schedule THF – C2. It reflects the income tax effect of the pro forma changes in income and expense items.

COST OF SERVICE - RATE DESIGN

Q. Are you proposing a rate design for the Company to use to recover its revenue deficiency?

A. Yes.

Q. What is the underlying rationale for the structure and magnitude of the tariffs you are proposing?

A. The underlying rationale for the structure and magnitude of the tariffs that I am proposing is that they should be efficient, equitable, and result in providing the Company the opportunity to recover its cost of providing service. Rates should be simple and easy to understand, and minimize revenue fluctuations, they should be efficient in the sense that wasteful production and consumption practices are discouraged, and they should not be discriminatory. With respect to rate levels and customer charges, while cost-based rates are an important consideration in rate design, gradualism is also important.

Q. Would you give a general overview of natural gas rates?

A. Yes. Generally, costs for natural gas service consists of two parts. First is a customer, or fixed, charge and second, is a volumetric, or usage, charge. With respect to the fixed charge, movement to cost-based rates (assuming the costs are calculated correctly), should not be so abrupt as to cause rate shock.

Q. What is the procedure you used to determine your proposed tariffs?

A. The first step is to determine the Company's revenue requirement. This task was accomplished in the previous Sections of my testimony. The revenue requirement is defined as the Company's cost, including capital cost, of providing service. This cost of service is then apportioned to various customer groups on the basis of a cost of service study and rates designed to give the Company the opportunity to recover its cost of providing service.

Q. Did you have any special considerations in mind in designing the customer charge component of rates?

A. Yes. It is important to keep in mind that the Company has incentives to move as much cost, and therefore revenue recovery, to customer classes with the relatively greatest inelasticity of demand, i.e., residential customers. Demand for residential natural gas service is seasonal and the demand may fluctuate less than demand by other customer groups. By moving as much revenue recovery as possible to fixed monthly residential customers the Company may be passing more of its financial risk on to a customer class that adds comparatively little to that risk.

It is also important to consider intra-customer class cross-subsidization. In order to address a possible volumetric subsidization issue by moving revenue recovery from a volumetric basis to a customer charge basis, it is likely that the previously subsidizing customers could become subsidized customers. The net gain, then could be zero in that another subsidization problem is created.

Q. Did the Company prepare a cost of service study in support of its application for rate relief?

A. Yes. This was presented in the G Schedules in the Company's filing and was sponsored by Company Witness Erdwurm.

Q. Did the Company conduct its cost of service study consistent with previous Commission orders regarding cost of service?

A. Yes. According to Mr. Erdwurm the study follows the traditional structure previously approved in the Company's prior rate cases.

Q. Did you review the Company's cost study?

A. Yes. I conducted a review of the cost study. Based on my review I conclude that the Cost of Service study conducted for this proceeding is consistent with the Company's previous study.

Customer Assistance Residential Energy Support ("CARES") Program

Q. What is the CARES Program?

A. The CARES program provides for a discounted Minimum Customer charge of $7.00 per month throughout the calendar year. In addition, CARES customers receive a $.015 per therm monthly discount on the first 100 therms used during the winter billing months of

November through April. To be eligible for the CARES discount, the customer must have a gas account in their name and have a combined household income at or below 150 percent of the federal poverty level.

Q. Is the Company proposing a change in its CARES residential rate?

A. No. The Company is proposing to leave the CARES residential rate at its current level. That is $7.00 monthly customer charge and $.177 per therm for the first 100 therms used in the winter heating season and $.327 per therm after the first 100 therms in the winter heating season and in the summer.

Q. Is the Company proposing a change in the CARES tariff?

A. Yes. The Company is proposing to increase its R10 residential rate but not its CARES R12 residential rate. So the Company is proposing to de-link these two residential rates.

Q. What is the Warm Spirits Program?

A. Warm Spirits is a program where customers can help their neighbors by pledging a fixed amount which is added to their monthly bill or make a random contribution by entering the contribution amount on their bill payment coupon and include their amount with their monthly payment.

Q. Is the Company proposing changes in its low-income assistance programs?

A. Yes. The Company is proposing to hold meetings of interested stakeholders to discuss modifications to the CARES program. According to Company Witness Erdwurm the Company is agreeable to changes so long as they are funded by other retail customers and are billable through the customer information and billing system. With respect to its Warm Spirits Program the Company is proposing a "round-up" program. Under this program, customers who signed up for the program would see their bills "rounded up" to the next dollar and the difference between the actual bill amount and the rounded-up amount would be contributed to the Warm Spirits Program.

Q. Do you agree with the Company's proposals regarding expansion of its low-income assistance program?

A. Yes.

Rules and Regulations

Q. Is the Company proposing changes to its rules and regulations?

A. Yes. Mr. Smith presents the proposed changes on page 5 of his prepared testimony.

Q. What are the Company's proposed changes?

A. The Company is proposing the following changes to its Rules and Regulations:

Section 2 – Add definitions for "Elderly", "Excess Flow Valve", "Service Transfer", "Special Call Out" and "Trip Charge". Delete the definitions of "Senior Citizen" and "Working Hours". Clarify the definition of "Service Reconnection Charge";

Section 3 – Clarify the applicability of service establishment, reestablishment and reconnection charges, as well as the charges for service transfers and multiple attempts to connect;

Section 6 – Increase the charge for service line establishments from $16.00 per foot to $22.50 per foot. For those customers who perform the trenching work, the charge for service line establishments will increase from $12.00 per foot to $16.50 per foot;

Section 8 – Delete the "Table of Atmospheric Pressure Bases" by geographical zone descriptions in favor of a more simplified version that shows the atmospheric pressure bases within specific elevation ranges; and

Section 17 – Add the Statement of Additional Charges to the end of the Rules and Regulations.

Q. Do you agree with the Company's proposed changes to its Rules and Regulations?

A. Yes. The Company's explanation for its proposed changes to Sections 2, 3, and 8 appear to be reasonable. It's proposed modifications to charge for service line establishments, Section 6, appears to be based on the incremental cost of service line establishment. Section 17 is proposed by the Company so that the Statement of Additional Charges can be found in one place.

Q. Do you agree with the Company's proposed changes to Section 6?

A. In general, I agree with the changes. The Company addressed the possible problem of mis-pricing hook up fees which could result in existing customers subsidizing new customers. According to the Company, its proposed fees are based on incremental cost studies and, therefore, should eliminate possible cross subsidization of existing customers by new customers. However, the Company raised a valid concern regarding the possibility of higher hook-up fees placing it in a competitive disadvantage relative to other energy providers such as propane and electricity. I have requested any studies the Company may have that address this issue and propose that the Commission assure itself that the Company will not be placed in a competitive disadvantage because of the proposed rates. This could conceivably create an unintentional problem while solving another problem.

Statement of Additional Charges

Q. What is the Statement of Additional Charges?

A. As mentioned above, the Statement of Additional Charges is a consolidation of various charges into Section 17 of the Company's Rules and Regulations.

Q. What are the charges that the Company proposes to consolidate into Section 17, the Statement of Additional Charges?

A. Company Witness Smith presents the Company's proposed service fees on page 7 of his testimony. The current and proposed fees are:

	Current	Proposed
Trip Fee		
Service Transfer:	$15.00	$20.00
Collection Fee	$20.00	$20.00
Customer Requested Meter Re-Reads	$15.00	$20.00
Multiple Attempts to Connect	$15.00	$20.00
Service Establishment & Reestablishment		
During Working Hours	$25.00	$35.00
Reestablishment of Service Due to Non-Pymt		
During Working Hours	$45.00	$35.00
Service Establishment & Reestablishment		
Outside Normal Working Hours	$35.00	$50.00
Reestablishment of Service Due to Non-Pymt		
Outside Working Hours	$55.00	$50.00
Customer Requested Meter Test	$65.00	$90.00
Insufficient Funds	$15.00	$10.00
Interest on Customer Deposits	1-yr Treasury rate	

Q. Do you agree with the Company's proposed changes in its Statement of Additional Charges?

A. Yes. The Company has conducted incremental cost studies ("ICS") for most of these charges and the proposed rates are in line with the results of the ICS. The Company does not provide an ICS for insufficient funds charges, but is proposing to reduce that charge.

Changes to T-1 and T-2 Pricing Plans

Q. Does the Company propose changes to its T-1 and T-2 pricing plans?

A. Yes.

Q. What do the T-1 and T-2 pricing plans apply to?

A. They apply to certain large customers.

Q. What are the changes proposed by the Company for these plans?

A. The Company is proposing that the monthly operating window under which the Customer's cumulative imbalances must be within plus or minus 5 percent of the month's total of daily scheduled transportation quantities, plus any Company-approved imbalance adjustment quantity, or 10,000 therms, whichever is greater be changed to 1,500 therms.

Q. Do you agree with this proposed change?

A. Yes. Currently the Company's monthly imbalance cash out threshold under its El Paso Natural Gas tariff is only 20,000 therms. Permitting each transportation customer to affect up to one half its permitted limit places the Company at an unnecessary risk level.

Changes to Residential R10 Customer Charges

Q. What rate design changes does the Company propose for residential R10 customers?

A. The Company is proposing a phase-in over three years of an increase in customer charges with a corresponding reduction in distribution margin. These proposed rates are:

Year 1:	Customer charge:	$10.00
	Distribution Margin:	$0.3920
Year 2:	Customer charge:	$12.00
	Distribution Margin:	$0.3479
Year 3:	Customer charge:	$14.00
	Distribution Margin:	$0.3039

Q. What is the Company's justification for this proposal?

A. According to the Company, it is not recovering enough of its customer related costs in its customer charge. The Company asserts that its revenues are seasonal and that a volumetric-heavy rate structure contributes to its revenue instability. It claims that if it were permitted to increase its customer charge then its revenue instability would be reduced.

Q. Does the Company offer any other reasons in support of its proposed residential customer charge multi-year phase in?

A. Yes. The Company states that because of the nature of its service territory under its current rate structure customers in cooler areas have higher usage than customers in warmer areas and, as a result, subsidize customers in warmer areas. The Company suggests that adoption of its proposal would eliminate this subsidization.

Q. Do you agree with the Company's proposed multi-year phase in of increased customer charges?

A. No. The Company's proposal violates a basic rule of rate design, that is, that rates should be simple and easy to understand. The Company's proposal provides its R10 residential customers with a confusing and moving target. I recommend that the Commission not approve this type of rate design change because of the adverse impact on customers.

Q. Do you agree that the Company's proposed residential rate implementation plan would eliminate intra-customer class subsidies?

A. If it eliminated the subsidy identified by the Company, then it might create another subsidy. That would be a possible subsidization of its northern customers by its southern customers as a result of the increase in customer charge to southern customers relative to total cost of service. In my opinion, the fact that some customers in a customer class may use more or less natural gas than other customers does not form the basis for a radical change in rates and rate structure. The concept of gradualism is important and the Company appears to have been successful in increasing the customer charge, although not by as much or as rapidly as it might have wished.

Customer Class Risk.

Q. Dr. Fish, did you conduct a study to identify the risk associated with the Company's various customer classes?

A. Yes.

Q. What is a customer class risk study?

A. A customer class risk study is a study that identifies and quantifies the risk associated with customer classes. The Company claims that it requires a significant increase in R10 customer charges in order to align its customer charge with customer-related costs, because of possible subsidization of southern residential customers by northern residential customers, and because of the extreme fluctuations in revenue over the course of a year.

Q. What is customer class risk?

A. Unanticipated changes in consumption represent risk. The Company's sales can be expected to vary over time to some extent due to long-term growth and to seasonal and cyclical variation. To the extent that these changes in sales are regular, recurring, and predictable they do not represent risk. Unanticipated changes in consumption can be identified with the use of time series analysis and a measure of risk is the Coefficient of Variation. The Coefficient of Variation is the ratio of the standard deviation of a series of observations to its arithmetic mean, i.e., CV = s.d./mean.

Q. What did your customer class risk study indicate?

A. The results of the study are presented in Schedule THF – RD1. The Company provided monthly data for residential, commercial, industrial, public authority and total Company for at least five years. I conducted a time series analysis (TSCI) on the decatherm sales for these classes and total. In order to isolate the risk component of the series I removed the trend and seasonal components, leaving the cyclical and irregular components. The cyclical and irregular components represent risk and the Column headed Time Series, TSCI, TSCI/TS shows the coefficient of variation for each of the classes and total. As one would expect residential, commercial and public authority customer classes had a much lower coefficient of variation than did the industrial customer class. This is confirmed by the experience of the Company with an industrial customer that used a large quantity of natural gas during the test year then experienced a significant reduction in usage after the test year ended. The second column headed Raw Data, shows the coefficient of variation for the same classes using only the raw data. Again, as one would expect, the results are not so clear because known and measurable changes are not removed from the series.

Q. What do the results of your study indicate?

A. They suggest that while the Company is experiencing fluctuations in revenue over the course of a year, those fluctuations, outside of the industrial customer class, do not reflect a high level of risk. Since the proportion of industrial sales to total system sales is quite small, the negative impact of the industrial class on the Company is low. However, the Company does experience revenue fluctuations and although the fluctuations are highly predictable, should continue to take action to minimize possible adverse effects of these fluctuations.

Rate Design

Q. Did you identify the Company's revenue shortfall?

A. Yes. I determined that the Company had an Operating Income Deficiency of $2,077,601 and a Gross Revenue Requirement of $3,395,423.

Q. Did you prepare Schedules showing your proposed rate design?

A. Yes. I prepared Schedules THF – RD2 through THF – RD6 to present my rate design. Schedule THF – RD2 provides a summary of revenues by customer class adjusted present rates and proposed rates and Schedule THF – RD3 provides a summary of revenues by rate schedules adjusted present rates and proposed rates. Schedule THF – RD4 is a summary schedule showing current rates, proposed rates and change by class of service. Schedule THF – RD5 shows proof of revenues and Schedule THF – RD6 provides a typical bill comparison by major customer class.

Q. On Schedule THF - RD2 what is your proposed revenue increase for industrial customers I-30 and I-32?

A. The revenue increase in Schedule THF - RD2 is 49.74 percent.

Q. Is that the rate increase you are proposing for industrial customers I-30 and I-32?

A. No. On Schedule THF – RD5 I am proposing the following rate increase for industrial customers:

	Customer Charge	Distribution Margin
Small Industrial I-30	14.8%	8.5%
Large Industrial I-32	5%	21%

The aggregate proposed rate increase, shown in THF-RD6 is approximately 9 percent for both customer classes. The higher revenue increase results from the removal of an industrial customer's revenue from test year operations.

Q. Will your proposed rate increase for I-30 and I-32 customers prevent the Company from having the opportunity to recover its cost of providing service?

A. No. My proposed revenue increase for I-30 and I-32 customers is approximately 9.2 percent higher than the Company's current proposed revenue for those customer classes.

Q. Does that conclude your testimony?

A. Yes.

Schedules
Accompanying the Direct Testimony of Thomas H. Fish, Ph.D.

Schedule	Description
THF-1	Attachment 1 – Resume of Thomas H. Fish, Ph.D.
THF-2	Attachment 2 – Revenue Requirement/Rate Design Schedules
	Revenue Requirement
THF – A1	Revenue Deficiency
THF – A2	Revenue Conversion Factor
	Rate Base
THF – B1	Adjusted Rate Base
THF – B2	Summary of Adjustments to Rate Base
THF – B3	Adjusted Test Year RCND Rate Base
THF – B4	Comparative RCND Studies
THF – B5	Post Test Year Non Revenue Producing PIS
THF – B6	Customer Advances
THF – B7	Working Capital
THF – B8	Purchased Gas Lag
THF – B9	ADIT
THF – B10	Lead Lag
	Operating Income Adjustments
THF – C1	Adjusted Net Operating Income
THF – C2	Income Statement Adjustments Summary
THF – C3	Customer Annualization Summary
THF – C4	Customer Annualization Calculations
THF – C5	Weather Normalization
THF – C6	Rate Case Revenue
THF – C7	Bad Debt Expense
THF – C8	Fleet Fuel Expense
THF – C9	Postage Expense
THF – C10	AGA Expense
THF – C11	Legal Expenses
THF – C12	Call Center Expense
THF - C.13	Interest Synchronization
THF - C.14	Incentive Expense PEP
THF - C.15	Incentive Expense SERP
THF - C.16	Payroll Tax
THF - C.17	Rate Case Expense
	COS/Rate Design
THF – RD1	Customer Class Risk
THF – RD2	Summary of Revenues by Customer Class
THF – RD3	Summary of Revenues by Rate Schedule
THF – RD4	Summary of Staff Recommended Rate Design
THF – RD5	Proof of Revenue
THF – RD6	Bill Comparison

Attachment THF - 1

Curriculum Vita

Thomas H. Fish, PhD
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ADDRESS/PHONE

1020 Fredericksburg Rd.
Excelsior Springs, MO 64024
(816) 630-0628
email: tfish@ariadaireconomics.com

EDUCATION

University of Arkansas Ph.D., 1972, Major: Economics. Minors: Marketing/Management, Finance, and Quantitative Methods.

Central Missouri State University, 1970, Warrensburg: MA, Economics

University of Missouri - Kansas City, 1969, Kansas City BA, Economics

EXPERIENCE

Administrative proceedings – participated in over 80 proceedings involving economics, statistics, accounting, finance, market structure and industrial organization issues in telecommunications, electric, and oil and natural gas distribution industries.

Managerial experience – Over 20 years experience in managing private businesses. Experience in personnel, economics, market research, finance, accounting, and operations management. Managed technical departments in several firms and was group manager in many major projects.

Judicial proceedings – participated in over 70 proceedings involving antitrust, contract damages, insurance defense, economic loss, market structure and performance, and other related economics/statistics/finance issues.

Other engagements – participated in over 75 private industry and governmental engagements involving economics, market structure, statistics, finance, and operational issues.

Teaching Experience –Through July, 2003 Professor of Business and Economics at William Jewell College. Duties included teaching classes in Economics, Finance, Quantitative Methods, and Management.

Taught classes at Webster University, Avila College, and Longview Metropolitan College on an adjunct basis between 1984 and 1997. Taught graduate and undergraduate classes in the areas of Management, Marketing, Financial Accounting, Finance, Statistics, Quantitative Methods, and Economics.

Experience

1981-1986 Regulatory Consulting and Expert Witness Services. Ariadair Economics Group. Concentration on Regulatory Consulting and Expert Witness Services for Regulatory Commissions and Consumer Advocates.

1986-1987 Directory, Economics Department, LMSL Consultants, Overland Park, Kansas. Concentration on Regulatory Consulting and Expert Witness Services for Regulatory Commissions and Consumer Advocates.

1987-Present Judicial and Administrative litigation consultant and expert witness, Ariadair Economics Group. Regulatory consulting and the regulatory experience led to a large number of utility antitrust and related litigation engagements in addition to regulatory Commission and Consumer Advocate regulatory engagements. During the period 1981 -2000 taught on an adjunct basis at local colleges including Avila University and Webster University. During the period 1981-1999 had Consumer Advocate clients in Arizona, Nevada, Illinois, Ohio, Pennsylvania and Maine. Also during this period had Commission clients in Nebraska, Oklahoma, Tennessee, Pennsylvania, Missouri, and South Dakota,

2001-2006 Full Professor of Business and Economics at William Jewell College, Liberty, Mo. During this period also had several judicial litigation engagements involving asset valuation and economic loss..

PUBLICATIONS

"An Analysis of Valuation of Community Bank Stocks." Quarterly Community Bank Journal, April, 1983.

"An Analysis of Trends in Prices of Community Bank Control Sales." Quarterly Community Bank Journal, July, 1983.

"An Analysis of Publicly Traded Multi-Bank Holding Company Market Performance After Acquisition of Community Banks." Quarterly Community Bank Journal, October, 1983.

"Derivation of a Valuation Index for Community Bank Control Sales." Quarterly Community Bank Journal, January, 1984.

RESEARCH

Professional Presentation

"An Econometric Model of Missouri." Presented at the Missouri Valley Economic Association, 1974.

Consulting Research

Economic Impact of Various Utility Rate Structures on State and Regional Economies.

Demographic Analysis of Economic Regions.

Determination of Market Characteristics and Parameters for Jet Aircraft Manufacturing Firms.

Determination of Optimal Refinancing and Capital Structuring and Corresponding Cost of Capital and Return for Acquisitions and Mergers.

An Econometric Analysis of NECPA Pricing Policies.

An Econometric Analysis of the Effect of the Proposed 15% Severance Tax (Senate Bill #892) on the Economy of the State of Kansas.

Curtailment of Demand Econometric Model for Cincinnati Bell Telephone Company's Service Area.

Development of Control Procedures for Large Construction Projects.

Development of Automatic Bill of Materials Systems of Manufacturing Processes.

Development of Planning and Forecasting Models.

Utilization of Economic Analysis in Business Decision-Making Situations (Seminar).

A Long-Term Forecast of Relative Costs of Alternative Energy Sources.

Analysis of the Validity of Sampling Procedures for Determination of the Growth Component of the DCF Model.

Analysis of the Relative Risk of Customer Classes of Electric Companies.

Development of EDP Models for Determining Optimal Price, Financing Strategy, and Expected Return for Corporate Acquisitions and Mergers.

Analysis of Asset Valuation in Bankruptcy Cases.

Preparation of Bank Charter Applications and Supporting Economic/Demographic Analyses.

COLLEGES COURSE TAUGHT

Management

Bank Management
Financial Management
Global Issues in Business

Human Resource Management
International Business Management
Introduction to Business
Introduction to Management
Marketing Research
Organization and Management
Organizational Behavior
Small Business Management
Strategic Management
Telecommunications Management

Finance

Financial Management
Intermediate Finance
International Finance
Portfolio Selection
Principles of Finance
Readings in Finance
Seminar in Finance I
Seminar in Finance II

Quantitative Methods

Business Math
Econometrics I
Econometrics II
Quantitative Analysis I
Quantitative Analysis II
Statistics I
Statistics II

Computer Information Systems/Information Technology

Computer Applications in Business
IT Systems Analysis and Design
Systems Analysis and Design I
Systems Analysis and Design II

Economics

Advanced Microeconomics
Business Cycles and Forecasting
Current Issues in Economics
Econometrics I
Econometrics II
Fiscal Policy
Industrial Organization

Intermediate Macroeconomics
Intermediate Microeconomics
International Economics
Macroeconomics
Managerial Economics
Microeconomics
Money and Banking
Principles of Econ I
Principles of Econ II
Readings in Economics

Financial Accounting

Cost Accounting
Federal Income Tax
Financial Accounting I
Financial Accounting II
Intermediate Financial Accounting
Managerial Accounting

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Revenue Requirement
Test Yeat Ended June 30, 2009

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) STAFF ORIGINAL COST	(C) COMPANY RCND	(D) STAFF RCND	(E) COMPANY FAIR VALUE	(F) STAFF FAIR VALUE
1	Adjusted Rate Base	$ 182,293,105	$ 178,509,369	$ 329,265,770	$ 324,538,937	$ 255,779,438	$ 251,524,153
2	Adjusted Operating Income (Loss)	$ 11,600,004	$ 13,544,256	$ 11,600,004	$ 13,544,256	$ 11,600,004	$ 13,544,256
3	Current Rate of Return (Line 2 / Line1)	6.36%	7.59%	3.52%	4.17%	4.54%	5.38%
4	Required Operating Income (Line 5 X Line 1)	$ 15,950,647	$ 14,709,172	$ 17,390,762	$ 14,727,023	$ 17,390,762	$ 14,727,023
	Plus fair value (Line 6)		$ 15,621,857		$ 15,621,857		$ 15,621,857
5	Required Rate of Return	8.75%	8.24%	8.75%	8.24%**	8.75%	8.24%**
6	Fair Value Adjustment*	0.79%	$ 912,685	-3.47%	$ 912,685	-1.95%	$ 912,685
7	Total	9.54%		5.28%		6.80%	
8	Operating Income Deficiency (Line 4 - Line 2)***	$ 5,790,758	$ 2,077,601	$ 5,790,758	$ 2,077,601	$ 5,790,758	$ 2,077,601
9	Gross Revenue Conversion Factor	1.6366	1.6343	1.6366	1.6343	1.6366	1.6343
10	Increase in Gross revenue requirement	$ 9,480,876	$ 3,395,423	$ 9,480,876	$ 3,395,423	$ 9,480,876	$ 3,395,423

References:

Columns (A), (C), and (E) Company Schedules A-1, C-1, and D-1
Column (B), Schedules THF-B-1, THF-C-1
Column (D), Schedule THF- B-1, THF - C-1
Column (F), Average of Columns (B) and (D)
Line 7, Company adopted Staff and RUCO Tax values from Docket G-04204A-06-0463
*Staff Fair Value Adjustment = (FVRB-OCRB)*risk free rate [1.25%]
**Staff Witness Parcell
***Line 4 + Line 6

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Gross Revenue Conversion Factor
Test Yeat Ended June 30, 2008

LINE NO.	DESCRIPTION	REFERENCE	(A) PERCENTAGE
1	Revenues		100.00%
2	Less Uncollectibles	Company Schedule C-3, Line 2	0.3468%
3	Subtotal	Line 1 - Line 2	99.6532%
4	Less State Income Tax (6.968%) and Federal Income Tax (31.63%)	Line 3 X 38.598%	38.4641%
5	Change in Net Operating Income	Line 3 - Line 4	61.1891%
6	Gross Revenue Conversion Factor	Line 1 / Line 5	1.6343

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Original Cost and RCND Adjusted Rate Base
Test Yeat Ended June 30, 2009

LINE NO.	DESCRIPTION	(A) COMPANY ORIGINAL COST	(B) OCRB STAFF ADJUSTMENTS	(C) OCRB AS ADJUSTED BY STAFF	(D) COMPANY RCND	(E) RCND STAFF ADJUSTMENTS	(F) RCND AS ADJUSTED BY STAFF
1	Gross Utility Plant in Service	$ 318,227,624	$ (1,527,588)	$ 316,700,036	$ 561,025,858	$ (2,514,427)	$ 558,511,431
2	Less: Accumulated Depreciation	$ 87,543,544		$ 87,543,544	$ 152,278,962		$ 152,278,962
3	Net Utility Plant in Service	$ 230,684,080		$ 229,156,492	$ 408,746,896		$ 406,232,469
4	Southern Union Acquisition Premium						
5	Less: Accum Amort. So. Union Acq. Premium				$ 3,553		$ 3,553
6	Net Southern Union Acquisition Premium				$ (3,553)		$ (3,553)
7	Citizens Acquisition Discount	$ (30,709,737)		$ (30,709,737)	$ (55,128,579)		$ (55,128,579)
8	Less: Accumulated Amort. - Citizens Acq. Discount	$ (3,935,647)		$ (3,935,647)	$ (6,658,438)		$ (6,658,438)
9	Net Citizens Acquisition Discount	$ (26,774,090)		$ (26,774,090)	$ (48,470,141)		$ (48,470,141)
10	Total Net Utility Plant	$ 203,909,990		$ 202,382,402	$ 360,273,202		$ 357,758,775
11	Customer Advances for Construction	$ (11,235,876)	$ 589,152	$ (11,825,028)	$ (12,759,773)	$ 589,152	$ (13,348,925)
12	Customer Deposits	$ (2,609,271)		$ (2,609,271)	$ (2,609,271)		$ (2,609,271)
13	Accumulated Deferred Income Taxes	$ (10,606,875)	$ 38,994	$ (10,645,869)	$ (18,474,527)	$ 38,994	$ (18,513,521)
14	Total Deductions	$ (24,452,022)		$ (25,080,168)	$ (33,843,571)	$ -	$ (34,471,717)
15	Allowance for working Capital	$ 2,364,921	$ 1,628,004	$ 736,917	$ 2,364,921	$ 1,628,004	$ 736,917
16	Regulatory Assets	$ 492,590		$ 492,590	$ 492,590		$ 492,590
17	Regulatory Liabilities	$ (22,372)		$ (22,372)	$ (22,372)		$ (22,372)
18	Total Rate Base	$ 182,293,107		$ 178,509,369	$ 329,264,770		$ 324,538,937

References:
Columns (A) and (D) Company Schedule B-1

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Original Cost Rate Base Pro Forma Adjustments
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION	(A) COMPANY ACTUAL END OF TEST YEAR	(B) COMPANY ADJUSTMENTS	(C) COMPANY ADJUSTED END OF TEST YEAR	(D) Post TY Non-Rev Plnt in Ser	(E) Customer Advances Adjst	(F) Accum Def Income Taxes
1	Gross Utility Plant in Service	$ 340,154,214	$ (21,926,590)	$ 318,227,624	$ (1,527,588)		
			$ -				
2	Less: Accumulated Depreciation	$ 93,765,398	$ (6,221,854)	$ 87,543,544			
3	Net Utility Plant in Service	$ 246,388,816	$ (15,704,736)	$ 230,684,080	$ (1,527,588)		
4	Southern Union Acquisition Premium	$ 18,271,349	$ (18,271,349)	$ -			
5	Less: Accum Amort. So. Union Acq. Premium	$ 2,125,967	$ (2,125,967)	$ -			
6	Net Southern Union Acquisition Premium	$ 16,145,382	$ (16,145,382)	$ -			
7	Citizens Acquisition Discount	$ (68,391,292)	$ 37,681,555	$ (30,709,737)			
8	Less: Accumulated Amort. - Citizens Acq. Discount	$ (8,764,777)	$ 4,829,130	$ (3,935,647)			
9	Net Citizens Acquisition Discount	$ (59,626,515)	$ 32,852,425	$ (26,774,090)			
10	Total Net Utility Plant	$ 202,907,683	$ 1,002,307	$ 203,909,990	$ (1,527,588)		
11	Customer Advances for Construction	$ (11,825,028)	$ 589,152	$ (11,235,876)		$ (589,152)	
12	Customer Deposits	$ (2,609,271)	$ -	$ (2,609,271)			
13	Accumulated Deferred Income Taxes	$ (15,056,983)	$ 4,450,108	$ (10,606,875)			$ (38,994)
14	Total Deductions	$ (29,491,282)	$ 5,039,260	$ (24,452,022)			
15	Allowance for working Capital	$ 2,266,954	$ 97,967	$ 2,364,921			
16	Regulatory Assets	$ 492,590	$ -	$ 492,590			
17	Regulatory Liabilities	$ (22,372)	$ -	$ (22,372)			
18	Total Rate Base	$ 176,153,573	$ 6,139,534	$ 182,293,107	$ (1,527,588)	$ (589,152)	$ (38,994)

References:
Columns (A) and (C) Company Schedule B-2

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Original Cost Rate Base Pro Forma Adjustments
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION	(G) Working Capital	(H) STAFF ADJUSTMENTS	(I) AS ADJUSTED BY STAFF
1	Gross Utility Plant in Service		$ (1,527,588)	$ 316,700,036
				$ -
2	Less: Accumulated Depreciation			$ 87,543,544
3	Net Utility Plant in Service		$ (1,527,588)	$ 229,156,492
4	Southern Union Acquisition Premium			$ -
5	Less: Accum Amort. So. Union Acq. Premium			$ -
6	Net Southern Union Acquisition Premium			$ -
7	Citizens Acquisition Discount			$ (30,709,737)
8	Less: Accumulated Amort. - Citizens Acq. Discount			$ (3,935,647)
9	Net Citizens Acquisition Discount			$ (26,774,090)
10	Total Net Utility Plant		$ (1,527,588)	$ 202,382,402
11	Customer Advances for Construction		$ (589,152)	$ (11,825,028)
12	Customer Deposits			$ (2,609,271)
13	Accumulated Deferred Income Taxes		$ (38,994)	$ (10,645,869)
14	Total Deductions			$ (25,080,168)
15	Allowance for working Capital	$ (1,628,004)	$ (1,628,004)	$ 736,917
16	Regulatory Assets		$ -	$ 492,590
17	Regulatory Liabilities		$ -	$ (22,372)
18	Total Rate Base	$ (1,628,004)	$ (3,783,738)	$ 178,509,369

References:
Columns (A) and (C) Company Schedule B-2

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Adjusted Test Year RCND Rate Base
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION	(A) 06-0463 COMMISSION ORIGINAL COST RATE BASE	(B) 06-0463 COMMISSION RCND RATE BASE	(C) 08-0571 COMPANY ORIGINAL COST RATE BASE	(D) 08-0571 COMPANY RCND RATE BASE	(E) % COLUMN B OF COLUMN A	(F) % COLUMN D OF COLUMN C
1	Gross Utility Plant in Service	$ 271,980,463	$ 367,054,190	$ 318,227,624	$ 561,025,858	134.956%	176.297%
2	Less: Accumulated Depreciation	$ 72,006,708	$ 97,114,865	$ 87,543,544	$ 152,278,962	134.869%	173.947%
3	Net Utility Plant in Service	$ 199,973,755	$ 269,939,325	$ 230,684,080	$ 408,746,896	134.987%	177.189%
4	Southern Union Acquisition Premium						
5	Less: Accum Amort. So. Union Acq. Premium	$ -	$ -		$ 3,553		
6	Net Southern Union Acquisition Premium	$ -	$ -		$ (3,553)		
7	Citizens Acquisition Discount	$ (30,709,738)	$ (41,822,562)	$ (30,709,737)	$ (55,128,579)	136.187%	179.515%
8	Less: Accumulated Amort. - Citizens Acq. Discount	$ (1,876,981)	$ (2,560,308)	$ (3,935,647)	$ (6,658,438)	136.406%	169.183%
9	Net Citizens Acquisition Discount	$ (28,832,757)	$ (39,262,254)	$ (26,774,090)	$ (48,470,141)	136.172%	181.034%
10	Total Net Utility Plant	$ 171,140,998	$ 230,677,071	$ 203,909,990	$ 360,273,202	134.788%	176.682%
11	Customer Advances for Construction	$ (7,283,595)	$ (7,786,962)	$ (11,235,876)	$ (12,759,773)	106.911%	113.563%
12	Customer Deposits	$ (3,040,484)	$ (3,040,484)	$ (2,609,271)	$ (2,609,271)	100.000%	100.000%
13	Accumulated Deferred Income Taxes	$ (6,289,473)	$ (6,289,473)	$ (10,606,875)	$ (18,474,527)	100.000%	174.175%
14	Total Deductions	$ (16,613,552)	$ (17,116,919)	$ (24,452,022)	$ (33,843,571)	103.030%	138.408%
15	Allowance for working Capital	$ (211,136)	$ (211,136)	$ 2,364,921	$ 2,364,921	100.000%	100.000%
16	Regulatory Assets	$ 307,819	$ 307,819	$ 492,590	$ 492,590	100.000%	100.000%
17	Regulatory Liabilities	$ (19,721)	$ (19,721)	$ (22,372)	$ (22,372)	100.000%	100.000%
18	Total Rate Base	$ 154,604,408	$ 213,637,114	$ 182,293,107	$ 329,264,770	138.183%	180.624%

References:
Columns (A) and (B) Company Schedule B-1 from Docket 06-0463
Columns (C) and (D) Company Schedule B-1 from Docket 08-0571
Column (E) Column B/Column A
Column (F) Column D/Column C
Column (G) Column C/Column A
Column (H) Column D/Column B
Column (I) Column B Times Column G

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Adjusted Test Year RCND Rate Base
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION	(G) % COLUMN C OF COLUMN A	(H) % COLUMN D OF COLUMN B	(I) COLUMN B TIMES COLUMN G
1	Gross Utility Plant in Service	117.004%	152.846%	$ 429,467,549
2	Less: Accumulated Depreciation	121.577%	156.803%	$ 118,069,270
3	Net Utility Plant in Service	115.357%	151.422%	$ 311,394,387
4	Southern Union Acquisition Premium			
5	Less: Accum Amort. So. Union Acq. Premium			
6	Net Southern Union Acquisition Premium			
7	Citizens Acquisition Discount	100.000%	131.815%	$ (41,822,561)
8	Less: Accumulated Amort. - Citizens Acq. Discount	209.680%	260.064%	$ (5,368,445)
9	Net Citizens Acquisition Discount	92.860%	123.452%	$ (36,458,918)
10	Total Net Utility Plant	119.147%	156.181%	$ 274,845,652
11	Customer Advances for Construction	154.263%	163.861%	$ (12,012,384)
12	Customer Deposits	85.818%	85.818%	$ (2,609,271)
13	Accumulated Deferred Income Taxes	168.645%	293.737%	$ (10,606,875)
14	Total Deductions	147.181%	197.720%	$ (25,192,883)
15	Allowance for working Capital	-1120.094%	-1120.094%	$ 364,921
16	Regulatory Assets	160.026%	160.026%	$ 492,590
17	Regulatory Liabilities	113.443%	113.443%	$ (22,372)
18	Total Rate Base	117.909%	154.123%	$ 251,898,208

References:
Columns (A) and (B) Company Schedule B-1 from Dock
Columns (C) and (D) Company Schedule B-1 from Dock
Column (E) Column B/Column A
Column (F) Column D/Column C
Column (G) Column C/Column A
Column (H) Column D/Column B
Column (I) Column B Times Column G

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Comparative RCND Studies
Test Yeat Ended June 30, 2008

LINE NO.	YEAR	A HW INDEX FERC 276 STEEL MAINS '05 RCN	B BASE 435 TREND VALUE FERC 277 STEEL MAINS '05 RCN BASE 435	C TREND VALUE FERC 278 STEEL MAINS '05 RCN BASE 556	D ACTUAL TREND TO RCN STY TREND	E HW INDEX FERC 278 STEEL MAINS '08 RCN	F TREND VALUE FERC 279 STEEL MAINS '08 RCN	G CORRECT 08 TRND TP '05 TREND
1	1998	308	141.234%	180.519%	127.816%	308	183.442%	101.619%
2	1999	336	129.464%	165.476%	127.816%	336	168.155%	101.619%
3	2000	354	122.881%	157.062%	127.816%	354	159.605%	101.619%
4	2001	360	120.833%	154.444%	127.816%	360	156.944%	101.619%
5	2002	367	118.529%	151.499%	127.816%	367	153.951%	101.619%
6	2003	372	116.935%	149.462%	127.816%	372	151.882%	101.619%
7	2004	435	100.000%	127.816%	127.816%	435	129.885%	101.619%
8	2005	435	100.000%	100.000%	100.000%	556	101.619%	101.619%
9	2006					599	94.324%	
10	2007					560	100.893%	
11	2008					565	100.000%	

References:

A: From TY '05 Company RCN Study
B: 435 divided by column A value
C: 556 divided by column A value
D: Column C divided by Column B
E: From TY 06/30/08 RCN Study
F: 565 divided by Column E
G: Column F divided by Column D

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Post Test Year Non-Revenue Plant
Test Yeat Ended June 30, 2008

LINE NO.	DESCRIPTION		AMOUNT	REFERENCE
1	Remove Post Test Year Non-Revenue Plant	$	(1,527,588)	A & B

Reference

A: UNS Gas Filing, Schedule B-2
B: Testimony of Staff Witness Thomas Fish, PhD

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Customer Advances Adjustment
Test Yeat Ended June 30, 2008

LINE NO.	DESCRIPTION		AMOUNT	REFERENCE
1	Remove Post Test Year Customer Advances Adjustment	$	(589,152)	A & B

Reference

A: UNS Gas Filing, Schedule B-2
B: Testimony of Staff Witness Thomas Fish

UNS Gas, Inc
Docket No. G-04204A-08-0571
Working Capital Adjustment
Test Year Ended June 30, 2009

line no.	Discription		net change	
1	cash working capital per UNS	1588		lead/lag
2	cash working capital per staff	-1626428		
3	net adjustment requirement	-1624840	-1624840	
4	Materials and supplies per UNS	2010788		sched. THF-B8
5	Materials and supplies per staff	2010788		
6	net adjustment required	0	0	
7	Prepayments per UNS	352564		sched. THF-B8
8	Prepayments per staff	352564		
9	net adjustment required	0	0	
10	Total Working Capital Adjustment		-1624840	

UNS Gas
Docket No. G-04024A-08-0571
Purchased Gas Lag
Test Year Ending June 30, 2009

Service Month	Service Period Begin	End	Amount Paid	Payment Date	Lag Days (a)		Dollar Days
BP Energy Company							
July -	7/1/2007	7/31/2007	2,892,390	8/20/2007	35.00		101,233,667
August -	8/1/2007	8/31/2007	2,811,862	9/20/2007	35.00		98,415,166
September -	9/1/2007	9/30/2007	2,693,603	10/22/2007	36.50		98,316,498
October -	10/1/2007	10/31/2007	5,507,132	11/20/2007	35.00		192,749,607
November -	11/1/2007	11/30/2007	7,297,535	12/20/2007	34.50		251,764,943
December -	12/1/2007	12/31/2007	16,000,000	1/7/2008	35.00	b	560,000,000
December -	1/1/2008	1/15/2008	10,000,000	1/22/2008	35.00	b	350,000,000
January -	1/16/2008	1/31/2008	9,000,000	2/5/2008	35.00	b	315,000,000
January -	2/1/2008	2/15/2008	9,000,000	2/20/2008	35.00	b	315,000,000
February -	2/16/2008	2/29/2008	9,373,701	3/19/2008	35.00	b	328,079,540
March -	3/1/2008	3/31/2008	12,389,177	4/22/2008	37.00		458,399,562
April -	4/1/2008	4/30/2008	7,801,472	5/22/2008	36.50		284,753,743
May -	5/1/2008	5/31/2008	7,264,481	6/20/2008	35.00		254,256,849
June -	6/1/2008	6/30/2008	7,826,991	7/21/2008	35.50		277,858,167
			109,858,344				3,885,827,742
El Paso Natural Gas Co							
July -	7/1/2007	7/31/2007	379,421	8/24/2007	39.00		14,797,438
August -	8/1/2007	8/31/2007	377,627	9/25/2007	40.00		15,105,098
September -	9/1/2007	9/30/2007	388,581	10/25/2007	39.50		15,348,942
October -	10/1/2007	10/31/2007	438,071	11/25/2007	40.00		17,522,849
November -	11/1/2007	11/30/2007	976,464	12/21/2007	35.50		34,664,462
December -	12/1/2007	12/31/2007	1,273,618	1/25/2008	40.00		50,944,716
January -	1/1/2008	1/31/2008	1,267,429	2/25/2008	40.00		50,697,160
February -	2/1/2008	2/28/2008	1,239,857	3/24/2008	39.50		48,974,366
March -	3/1/2008	3/31/2008	1,190,404	4/22/2008	37.00		44,044,947
April -	4/1/2008	4/30/2008	568,207	5/27/2008	41.50		23,580,588
May -	5/1/2008	5/31/2008	338,302	6/23/2008	38.00		12,855,459
June -	6/1/2008	6/30/2008	352,906	7/25/2008	39.50		13,939,806
			8,790,888				342,475,831
Transwestern Pipeline Co							
July -	7/1/2007	7/31/2007	104,768	8/13/2007	28.00		2,933,518
August -	8/1/2007	8/31/2007	104,727	9/14/2007	29.00		3,037,089
September -	9/1/2007	9/30/2007	101,557	10/12/2007	26.50		2,691,256
October -	10/1/2007	10/31/2007	260,164	11/9/2007	24.00		6,243,936
November -	11/1/2007	11/30/2007	252,179	12/13/2007	27.50		6,934,912
December -	12/1/2007	12/31/2007	263,779	1/14/2008	29.00		7,649,581
January -	1/1/2008	1/31/2008	264,531	2/11/2008	26.00		6,877,800
February -	2/1/2008	2/28/2008	246,162	3/13/2008	28.50		7,015,611
March -	3/1/2008	3/31/2008	302,830	4/11/2008	26.00		7,873,585
April -	4/1/2008	4/30/2008	331,575	5/12/2008	26.50		8,786,729
May -	5/1/2008	5/31/2008	241,646	6/12/2008	27.00		6,524,454
June -	6/1/2008	6/30/2008	182,318	7/11/2008	25.50		4,649,105
			2,656,236				71,217,578
			121,305,468				4,299,521,150
Average Lag Days				35.44			

(a) Measured from midpoint of service month to payment date.

(b) unusual payment terms

December -	12/1/2007	12/31/2007	16,000,000	1/7/2008	22.00	a	352,000,000
December -	1/1/2008	1/15/2008	10,000,000	1/22/2008	14.00	a	140,000,000
January -	1/16/2008	1/31/2008	9,000,000	2/5/2008	12.50	a	112,500,000
January -	2/1/2008	2/15/2008	9,000,000	2/20/2008	12.00	a	108,000,000
February -	2/16/2008	2/29/2008	9,373,701	3/19/2008	25.50	a	239,029,379
			53,373,701				951,529,379

Average days for Dec. Jan. & Feb. for BP 17.83

Source: Company Lead-Lag study work papers

UNS Gas. Inc
Docket No. G-04204A-08-0571
ADIT Adjustment
Test Year Ended June 30, 2009

Income Taxes:			**Deferred**			staff adjustments
Permanent Differences:						
Meals & Entertainment		$	-			
Normalized Timing Differences:						
263A Costs	**A1.1A**	$	(360,013)			
CARES Reg Asset	**C1A**	$	164,197			
Depr/Amort. - Book	**1.2B**	$	7,731,569			
Depr/Amort. - Tax	**1.2C**	$	(14,574,215)			
Dividend Equivalents	**H1A**	$	23,687			
Pension	**I1A**	$	3,793			
Repairs Capitalized	**J1A**	$	(816,406)			
Restricted Stock	**K1A**	$	19,372			
Restricted Stock - Directors	**L1B**	$	73,816			
SERP	**M1A**	$	101,021		$	(101,021)
Stock Options	**L1A**	$	149,525			
Vacation Accrual	**N1A**	$	49,544			
Total Normalized Timing Differences		$	(7,434,110)	#	$	(101,021)
Total Schedule M Items		$	(7,434,110)	#	$	(101,021)
Tax Credits:						
Arizona Enterprise Zone Credit (3 yr. avg.)			-			
Tax Rate			38.6%			38.6%
Deferred Tax Expense			**2,869,418**			**38,994**

UNS Gas Inc
Docket No. G-04204A-08-0571
Lead-Lag Study
Test Year Ended June 30, 2008

Description	FERC	Pro Forma Test Year Amount	adjustment	adjusted amount	Ref (1)	Revenue Lag Days	Expense Lag Days	Net Lag Days ;ol. C - Col. I	Lead/Lag Factor (Col. E/365)	Cash Working Capital Required (Col. F X Col.B)
(A)		(B)	(C)	(D)		(E)	(F)	(G)	(F)	(G)
Operating Expenses:										
Non-Cash Expenses -										
Bad Debts Expense	904	$ 688,379	$ 185,933	502,446	THF--C7					$ -
Depreciation	403/404	9,057,437		9,057,437						-
Amortization	Multi	(817,432)		(817,432)						-
Deferred Income Taxes	410/411	2,869,418	38,994	2,830,424	THF--B9					-
Other Operating Expenses -										
Salaries and Wages	Multi	7,750,405	10,905	7,739,500	THF--C16	40.70	24.50	16.20	0.0444	343,634
Incentive Pay	Multi	310,278	310,278	-	THF--C15	40.70	267.00	(226.30)	(0.6200)	-
Purchased Gas	555	87,528,793		87,528,793	THF--B8	40.70	35.44	5.26	0.0144	1,260,415
Office Supplies and Expenses	921	1,057,383	(49,594)	1,106,977	THF--C9	40.70	20.72	19.98	0.0547	60,552
Injuries and Damages	925	508,477		508,477		40.70	64.75	(24.05)	(0.0659)	(33,509)
Pensions and Benefits	926	1,544,121		1,544,121		40.70	54.66	(13.96)	(0.0382)	(58,985)
Support Services - TEP (Direct	Note A.	7,079,483	968,123	6,111,360	"A"	40.70	44.75	(4.05)	(0.0111)	(67,836)
Property Taxes	408	3,610,079		3,610,079		40.70	213.00	(172.30)	(0.4721)	(1,704,318)
Payroll Taxes	408	560,124	834	559,290	THF--C16	40.70	19.41	21.29	0.0583	32,607
Current Income Taxes	409	734,254	1,267,490	(533,236)	THF--C2	40.70	41.42	(0.72)	(0.0020)	1,066
Interest on Customer Deposits	431	137,200		137,200		40.70	182.50	(141.80)	(0.3885)	(53,302)
Other Operations and Mainten	Multi	6,212,916	294,599	5,918,317	THF-C8	40.70	53.10	(12.40)	(0.0340)	(201,223)
Total Operating Expenses		$128,831,315	$ 3,027,562	$ 125,803,753						
Other Cash Working Capital Elements:										
Interest on Long-Term Debt	Calc	5,924,526	(54,906)	5,979,432	THF--C13	40.70	89.50	(48.80)	(0.1337)	(799,450)
Revenue Taxes and Assessme	Calc	13,847,423	(968,117)	14,815,540	"C"	40.70	50.70	(10.00)	(0.0274)	(405,946)
Total Cash Working Capital-calculated										$ (1,626,296)
Total Cash Working Capital-per UNS										1,568
Change in working capital per staff										(1,627,864)
ProForma Operating Expenses - Excluding Income		$ 37,698,831	"C"	PER THF	"A"	1,614.00	AGA	THF--C10		
Purchased Gas Lead/Lag Only		87,528,793	REVENUE	144,874,080		484,798.00	CALL CENTE!	THF--C12		
ProForma Oper. Exp. To Tie Too - Excl Income Ta		125,227,624	RATE	0.0889		117,394.00	INCENTIVE	THF--C14		
Less: 1, 2, 3, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14		119,014,727		12,879,306		305,984.00	LEGAL EXPEI	THF--C11		
Other O&M		$ 6,212,897	CUR. REVENU	(13,847,423)		58,333.00	RATE CASE E	THF--C17		
			CHANGE	(968,117)		968,123.00				

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Adjusted Net Operating Income
Test Yeat Ended June 30, 2009

LINE NO.	DESCRIPTION	(A) COMPANY UNADJUSTED	(B) COMPANY PRO FORMA ADJUSTMENTS	(C) COMPANY ADJUSTED	(D) STAFF ADJUSTMENTS	(E) STAFF ADJUSTED
	Operating Revenues					
1	Gas Retail Revenues	$ 161,759,581	$ (110,601,818)	$ 51,157,763	$ 1,499,373	$ 52,657,136
2	Other Operating Revenue	$ 1,636,425	$ 108,318	$ 1,744,743		$ 1,744,743
3	Total Operating Revenues	$ 163,396,006	$ (110,493,500)	$ 52,902,506	$ 1,499,373	$ 54,401,879
	Operating Expenses					
4	Purchased Gas	$ 109,328,534	$ (108,930,899)	$ 397,635		$ 397,635
5	Other Operations and Maint Expense	$ 24,753,535	$ (34,422)	$ 24,719,113	$ (1,655,319)	$ 23,063,794
6	Depreciation and Amortization	$ 8,437,470	$ (197,465)	$ 8,240,005		$ 8,240,005
7	Taxes Other than Income Taxes	$ 3,000,914	$ 1,341,164	$ 4,342,078	$ (11,739)	$ 4,330,339
8	Income Taxes	$ 4,428,062	$ (824,391)	$ 3,603,671	$ 1,222,179	$ 4,825,850
9	Total Operating Expenses	$ 149,948,515	$ (108,646,013)	$ 41,302,502	$ (444,879)	$ 40,857,623
10	Operating Income	$ 13,447,491	$ (1,847,487)	$ 11,600,004	$ 1,944,252	$ 13,544,256
	Other Income and Deductions					
11	Allowance for Equity Funds	$ 137,755				
12	Other - Net	$ 241,016				
13	Total Other Income and Deductions	$ 378,771				
14	Income Before Interest Expense	$ 13,826,262				
	Interest Expense					
15	Interest on Long-Term Debt	$ 6,429,478				
16	Other Interest Expense	$ 324,398				
17	Allowance for Borrowed Funds	$ (101,633)				
18	Total Interest Expense	$ 6,652,243				
19	Net Income Available for common Stock	$ 7,174,019				

References:
Columns (A) and (C) Company Schedule E-2, C-2, A-1, A-2

UNS Gas, Inc
Docket No. G-04204A-08-0571
Adjustments to Net Opereating Revenue
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION	(A) Incentive Expense SERP	(B) Incentive Expense PEP	(C) Customer Annualization	(D) Weather Normalization	(E) Payroll Tax Expense	(F) Rate Case Expense
	Operating Revenues						
1	Gas Retail Revenues			$ 1,171,771	$ (21,436)		
2	Other Operating Revenue						
3	Total Operating Revenues			$ 1,171,771	$ (21,436)		
	Operating Expenses						
4	Purchased Gas						
5	Other Operations and Maint Expense	$ (310,412)	$ (117,393)				$ (58,333)
6	Depreciation and Amortization						
7	Taxes Other than Income Taxes					$ (11,739)	
8	Income Taxes						
9	Total Operating Expenses	$ (310,412)	$ (117,393)			$ (11,739)	$ (58,333)
10	Operating Income	$ 310,412	$ 117,393	$ 1,171,771	$ (21,436)	$ 11,739	$ 58,333

References: Schedules THF - C3 -THF - C17

UNS Gas, Inc
Docket No. G-04204A-08-0571
Adjustments to Net Opereating Revenue
Test Year Ended June 30, 2008

Schedule THF C2
Page 2 of 3

LINE NO.	DESCRIPTION	(G) Rate Case Revenue	(H) Call Center	(I) AGA Expense	(J) Legal Expenses	(K) Fleet Fuel Expense	(L) Interest Synchronization
	Operating Revenues						
1	Gas Retail Revenues	$ 349,038					
2	Other Operating Revenue						
3	Total Operating Revenues	$ 349,038					
	Operating Expenses						
4	Purchased Gas						
5	Other Operations and Maint Expense	$	(484,798) $	(1,673) $	(305,984) $	(294,599) $	54,906
6	Depreciation and Amortization						
7	Taxes Other than Income Taxes						
8	Income Taxes						
9	Total Operating Expenses	$	(484,798) $	(1,673) $	(305,984) $	(294,599) $	54,906
10	Operating Income	$ 349,038 $	484,798 $	1,673 $	305,984 $	294,599 $	(54,906)

References: Schedules THF - C3 -THF - C17

UNS Gas, Inc
Docket No. G-04204A-08-0571
Adjustments to Net Opereating Revenue
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION	(M) Postage Expense	(N) Bad Debt Expense	(O) Income Tax	TOTAL STAFF ADJUSTMENTS
	Operating Revenues				
1	Gas Retail Revenues				$ 1,499,373
2	Other Operating Revenue				$ -
3	Total Operating Revenues				$ 1,499,373
	Operating Expenses				
4	Purchased Gas				$ -
5	Other Operations and Maint Expense	$ 49,594	$ (186,627)		$ (1,655,319)
6	Depreciation and Amortization				
7	Taxes Other than Income Taxes				$ (11,739)
8	Income Taxes			$ 1,222,179	$ 1,222,179
9	Total Operating Expenses	$ 49,594	$ (186,627)		$ (444,879)
10	Operating Income	$ (49,594)	$ 186,627	$ -	$ 1,944,252
			Tax rate:	0.38598	

References: Schedules THF - C3 -THF - C17

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Adjustment to Annualize Retail Customer Sales
Test Yeat Ended June 30, 2008

LINE NO.	DESCRIPTION		AMOUNT	REFERENCE
1	UNS Gas Adjustment to Annualize Retail Revenue	$	(302,550)	A
2	Staff Adjustment to Annualize Retail Revenue	$	869,221	B
3	Net Staff Adjustment to Annualize Gas Retail Revenue	$	1,171,771	Line 2- Line 1

References:
- A: UNS Gas Filing, Schedule C-2
- B: Staff workpapers, C-2, Schedule THF - 2.1a

UNS Gas, Inc
Docket No. G-04204A-08-0571
Customer Annualization Calcs
Test Year Ended June 30,2008

Month	R10 Cust	R10 Adjustment	R10 Adjusted	R12 Cust	R12 Adjustment	R12 Adjusted
Jul-07	124,445	3,667	128,112	6,456	349	6,805
Aug-07	124,320	3,792	128,112	6,473	332	6,805
Sep-07	124,871	3,241	128,112	6,437	368	6,805
Oct-07	125,497	2,615	128,112	6,576	229	6,805
Nov-07	125,973	2,139	128,112	6,674	131	6,805
Dec-07	126,530	1,582	128,112	6,721	84	6,805
Jan-08	126,782	1,330	128,112	6,702	103	6,805
Feb-08	126,799	1,313	128,112	6,796	9	6,805
Mar-08	126,239	1,873	128,112	6,901	-96	6,805
Apr-08	125,566	2,546	128,112	7,027	-222	6,805
May-08	125,216	2,896	128,112	7,098	-293	6,805
Jun-08	124,957	3,155	128,112	7,077	-272	6,805
Totals	1,507,195	30,144	1,537,340	80,938	722	81,660

Month	R10 Delta Customer Charge	R12 Delta Customer Charge
Jul-07	$31,166	$2,443
Aug-07	$32,229	$2,324
Sep-07	$27,545	$2,576
Oct-07	$22,224	$1,603
Nov-07	$18,178	$917
Dec-07	$13,444	$588
Jan-08	$11,302	$721
Feb-08	$11,157	$63
Mar-08	$15,917	-$672
Apr-08	$21,638	-$1,554
May-08	$24,613	-$2,051
Jun-08	$26,814	-$1,904
Total Customer Charge	$256,228	$5,055
Total Delta Charges per Rate	$609,903	$7,368

$313,101	Total Customer Charge Delta		
$556,121	Total Therm Delivery Charge Delta		
$869,221	TOTAL	$869,221	Check total
34,440	Total Retail Customer Delta		
8	Total Transport Customer Delta		
34,448	Total Customer Delta		

UNS Gas, Inc
Docket No. G-04204A-08-0571
Customer Annualization Calcs
Test Year Ended June 30,2008

Month	C20 Cust	C20 Adjustment	C20 Adjusted	C22 Cust	C22 Adjustment	C22 Adjusted	C60 Cust	C60 Adjustment	C60 Adjusted
Jul-07	11,266	436	11,702	15	3	18	5	0	5
Aug-07	11,227	475	11,702	17	1	18	5	0	5
Sep-07	11,232	470	11,702	17	1	18	5	0	5
Oct-07	11,306	396	11,702	17	1	18	5	0	5
Nov-07	11,404	298	11,702	17	1	18	5	0	5
Dec-07	11,558	144	11,702	18	0	18	5	0	5
Jan-08	11,606	96	11,702	14	4	18	5	0	5
Feb-08	11,614	88	11,702	13	5	18	5	0	5
Mar-08	11,570	132	11,702	13	5	18	5	0	5
Apr-08	11,482	220	11,702	13	5	18	5	0	5
May-08	11,420	282	11,702	14	4	18	5	0	5
Jun-08	11,384	318	11,702	14	4	18	5	0	5
Totals	137,069	3,361	140,430	182	37	219	60	0	60

Month	C20 Delta Customer Charge	C22 Delta Customer Charge	C60 Delta Customer Charge
Jul-07	$5,892	$323	$1
Aug-07	$6,419	$123	$1
Sep-07	$6,351	$123	$1
Oct-07	$5,352	$123	$1
Nov-07	$4,029	$123	$1
Dec-07	$1,950	$22	$1
Jan-08	$1,302	$423	$1
Feb-08	$1,194	$523	$1
Mar-08	$1,788	$523	$1
Apr-08	$2,976	$523	$1
May-08	$3,813	$423	$1
Jun-08	$4,299	$423	$1
Total Customer Charge	$45,369	$3,670	$6
Total Delta Charges per Rate	**$190,033**	**$47,795**	**$400**

UNS Gas, Inc
Docket No. G-04204A-08-0571
Customer Annualization Calcs
Test Year Ended June 30,2008

Month	I30 Cust	I30 Adjustment	I30 Adjusted	I32 Cust	I32 Adjustment	I32 Adjusted
Jul-07	15	2	17	6	0	6
Aug-07	15	2	17	6	0	6
Sep-07	15	2	17	6	0	6
Oct-07	15	2	17	6	0	6
Nov-07	16	1	17	7	-1	6
Dec-07	16	1	17	7	-1	6
Jan-08	20	-3	17	5	1	6
Feb-08	20	-3	17	5	1	6
Mar-08	20	-3	17	5	1	6
Apr-08	20	-3	17	5	1	6
May-08	20	-3	17	5	1	6
Jun-08	20	-3	17	5	1	6
Totals	212	-7	205	68	5	73

Month	I30 Delta Customer Charge	I32 Delta Customer Charge
Jul-07	$29	$5
Aug-07	$29	$5
Sep-07	$29	$5
Oct-07	$29	$5
Nov-07	$15	-$95
Dec-07	$15	-$95
Jan-08	-$39	$105
Feb-08	-$39	$105
Mar-08	-$39	$105
Apr-08	-$39	$105
May-08	-$39	$105
Jun-08	-$39	$105
Total Customer Charge	($90)	$460
Total Delta Charges per Rate	($4,443)	($1,555)

UNS Gas, Inc
Docket No. G-04204A-08-0571
Customer Annualization Calcs
Test Year Ended June 30,2008

Month	PA40 Cust	PA40 Adjustment	PA40 Adjusted	PA42 Cust	PA42 Adjustment	PA42 Adjusted
Jul-07	1,054	23	1,077	5	0	5
Aug-07	1,057	20	1,077	5	0	5
Sep-07	1,058	19	1,077	5	0	5
Oct-07	1,059	18	1,077	5	0	5
Nov-07	1,060	17	1,077	5	0	5
Dec-07	1,065	12	1,077	5	0	5
Jan-08	1,066	11	1,077	5	0	5
Feb-08	1,066	11	1,077	5	0	5
Mar-08	1,066	11	1,077	5	0	5
Apr-08	1,067	10	1,077	5	0	5
May-08	1,064	13	1,077	5	0	5
Jun-08	1,065	12	1,077	5	0	5
Totals	12,747	178	12,925	60	0	60

Month	PA40 Delta Customer Charge	PA42 Delta Customer Charge
Jul-07	$312	$0
Aug-07	$271	$0
Sep-07	$258	$0
Oct-07	$244	$0
Nov-07	$231	$0
Dec-07	$163	$0
Jan-08	$150	$0
Feb-08	$150	$0
Mar-08	$150	$0
Apr-08	$136	$0
May-08	$177	$0
Jun-08	$163	$0
Total Customer Charge	$2,402	$0
Total Delta Charges per Rate	**$19,721**	**$0**

UNS Gas, Inc
Docket No. G-04204A-08-0571
Customer Annualization Calcs
Test Year Ended June 30,2008

Month	R10 Delta Therms Charge	R12 Delta Therms Charge
Jul-07	$16,217	$1,483
Aug-07	$16,026	$1,340
Sep-07	$14,835	$1,624
Oct-07	$17,229	$1,424
Nov-07	$22,908	$799
Dec-07	$36,570	$1,122
Jan-08	$49,163	$2,225
Feb-08	$46,660	$183
Mar-08	$44,638	-$1,332
Apr-08	$37,462	-$1,879
May-08	$29,719	-$2,839
Jun-08	$22,248	-$1,838
Total Delta Therm Charge	$353,675	$2,313

Delta Therms Per Rate Month	R10 Delta Therms	R12 Delta Therms
Jul-07	49,594	4,536
Aug-07	49,008	4,099
Sep-07	45,367	4,966
Oct-07	52,689	4,353
Nov-07	70,057	4,035
Dec-07	111,834	5,665
Jan-08	150,345	11,238
Feb-08	142,690	925
Mar-08	136,508	(6,726)
Apr-08	114,563	(9,489)
May-08	90,884	(8,681)
Jun-08	68,036	(5,621)
Totals	1,081,574	9,300

Total all Rates > 1,924,478 Therms < Total all Rates

UNS Gas, Inc
Docket No. G-04204A-08-0571
Customer Annualization Calcs
Test Year Ended June 30,2008

Month	C20 Delta Therms Charge	C22 Delta Therms Charge	C60 Delta Therms Charge
Jul-07	$11,533	$3,207	$101
Aug-07	$13,493	-$2,242	$59
Sep-07	$13,585	-$226	$81
Oct-07	$13,970	$733	$59
Nov-07	$13,499	$830	$30
Dec-07	$11,336	$336	$10
Jan-08	$11,062	$9,708	$9
Feb-08	$9,739	$8,461	$7
Mar-08	$9,933	$6,910	$7
Apr-08	$11,646	$6,267	$8
May-08	$12,980	$5,299	$15
Jun-08	$11,887	$4,843	$9
Total Delta Therm Charge	$144,663	$44,125	$394

Delta Therms Per Rate Month	C20 Delta Therms	C22 Delta Therms	60 C60 Delta Therms
Jul-07	43,717	18,665	315.9
Aug-07	51,149	(13,048)	185
Sep-07	51,497	(1,318)	253
Oct-07	52,958	4,265	186
Nov-07	51,170	4,830	94
Dec-07	42,972	1,954	31
Jan-08	41,935	56,507	28
Feb-08	36,919	49,249	22
Mar-08	37,652	40,221	23
Apr-08	44,148	36,477	24
May-08	49,204	30,845	46
Jun-08	45,060	28,192	27
Totals	548,382	256,839	1,234

UNS Gas, Inc
Docket No. G-04204A-08-0571
Customer Annualization Calcs
Test Year Ended June 30,2008

Month	I30 Delta Therms Charge	I32 Delta Therms Charge
Jul-07	$559	$1,021
Aug-07	$534	$938
Sep-07	$564	-$64
Oct-07	$1,256	-$641
Nov-07	$889	-$3,104
Dec-07	$1,249	-$428
Jan-08	-$2,760	$56
Feb-08	-$3,754	$67
Mar-08	-$1,449	$46
Apr-08	-$754	$33
May-08	-$462	$32
Jun-08	-$226	$29
Total Delta Therm Charge	**($4,353)**	**($2,015)**

Delta Therms Per Rate	30	32
Month	I30 Delta Therms	I32 Delta Therms
Jul-07	2,371.7	10,720.8
Aug-07	2,266	9,851
Sep-07	2,395	(673)
Oct-07	5,333	(6,735)
Nov-07	3,773	(32,609)
Dec-07	5,303	(4,494)
Jan-08	(11,716)	587
Feb-08	(15,932)	709
Mar-08	(6,152)	483
Apr-08	(3,200)	351
May-08	(1,960)	332
Jun-08	(959)	308
Totals	(18,477)	(21,168)

UNS Gas, Inc
Docket No. G-04204A-08-0571
Customer Annualization Calcs
Test Year Ended June 30,2008

Month	PA40 Delta Therms Charge	PA42 Delta Therms Charge
Jul-07	$481	$0
Aug-07	$407	$0
Sep-07	$475	$0
Oct-07	$739	$0
Nov-07	$1,525	$0
Dec-07	$2,310	$0
Jan-08	$3,276	$0
Feb-08	$3,115	$0
Mar-08	$2,258	$0
Apr-08	$1,189	$0
May-08	$992	$0
Jun-08	$552	$0
Total Delta Therm Charge	**$17,320**	**$0**

Delta Therms Per Rate Month	RtPA4 PA40 Delta Therms	RtPA PA42 Delta Therms
Jul-07	1,855.5	0.0
Aug-07	1,571	0
Sep-07	1,831	0
Oct-07	2,851	0
Nov-07	5,881	0
Dec-07	8,907	0
Jan-08	12,634	0
Feb-08	12,014	0
Mar-08	8,709	0
Apr-08	4,585	0
May-08	3,824	0
Jun-08	2,130	0
Totals	66,795	0

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Weather Normalization
Test Yeat Ended June 30, 2008

	(A)	(B)	(C)	(D)	(E)	(F)	(G)
LINE NO.	DESCRIPTION	UNS GAS WEATHER ADJUSTMENT	UNS GAS PROPOSED CUSTOMER COUNT	STAFF PROPOSED CUSTOMER COUNT	PERCENT OF STAFF ANNUALIZED TO COMPANY ANNUALIZED CUSTOMERS	STAFF WEATHER ADJUSTMENT	ADJUSTMENT TO PROPOSED COMPANY WEATHER ADJUSTMENT
1	R10	$ (651,725)	1,499,484	1,537,340	102.525%	$ (668,178.46)	$ (16,453.46)
2	R12	$ (26,564)	84,924	81,660	96.157%	$ (25,543.03)	1,021
3	C20	$ (146,996)	136,608	140,430	102.798%	$ (151,108.63)	(4,113)
4	C22	$ (4,413)	168	219	130.357%	$ (5,752.66)	(1,340)
5	IR60	$ (227)	60	60	100.000%	$ (227.00)	-
6	PA40	$ (48,582)	12,780	12,925	101.135%	$ (49,133.20)	(551)
7	PA42	$ (3,947)	60	60	100.000%	$ (3,947.00)	-
8		$ (882,454)	1,734,084	1,772,694	102.227%	$ (903,890)	(21,436)

Sources:
Column A: UNS Gas Proposed Weather Normalization Adjustment Workpapers
Column B: UNS Gas Proposed Customer Retail Sales Adjustment Workpapers
Column C: Staff's adjustmensts to UNS Gas Customer Adjustment workpapers
Column D: Column D divided by Column C.
Column F: Column E X Column B
Column G: Column F minus column B

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Rate Case Revenue Adjustment
Test Yeat Ended June 30, 2008

LINE NO.	DESCRIPTION	(A) AVERAGE THERMS PER CUSTOMER	(B) PRICE CHANGE PER THERM DEC. 1 2006	(C) CUSTOMER CHARGE CHANGE DEC. 1 2006	(D) STAFF CHANGE IN NUMBER OF CUSTS	(E) REVENUE CHANGE PER CUST CLASS
1	R10	570	0.026600	$1.50	15,133	$ 252,146.05
2	R12	499	0.026490	$0.00	-1360	$ (17,977.17)
3	C20	2,647	0.021800	$2.50	1588	$ 95,604.90
4	C22	218,533	0.016700	$15.00	20	$ 73,290.02
5	I30	33,371	0.023400	$2.50	-15	$ (11,750.72)
6	I32	1,137,376	0.008800	$15.00	-5	$ (50,119.54)
7	PA40	5,504	0.023300	$2.50	60	$ 7,844.59
8	PA42	637,510	0.011400	$15.00	0	$ -
9	IR60	14,467	0.031600	$2.50	0	$ -
AL (REVENUE ADJUSTMENT)						$ 349,038

Sources:
Column A, B, and C: UNS Gas Proposed Customer Retail Sales Adjustment Workpapers
Column D: UNS Gas Proposed Customer Adjustment Workpapers & Staff modifications to that spreadsheet.
Column E: Column A X Column B X Column D plus Column C X Column D.

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Bad Debt Expense
Test Yeat Ended June 30, 2008

LINE NO.	DESCRIPTION	AMOUNT	REFERENCE
1	Staff TY Adjusted Revenue	$ 54,200,000	Schedule THF - A-1
2	TY Gas Revenues	$ 90,472,202	Company Schedule C-2
3	Total TY Adjusted Revenues	$ 144,672,202	Line 1+ Line 2
4	Uncollectible Rate	0.3468%	Staff Adjustment(A)
5	Uncollectibles Expense	$ 501,752.13	Line 3 * Line 4
6	Uncollectibles per Company	$ 688,379.00	Company W/P(B)
7	Adjustment	$ (186,627)	Line 5 - Line 6

A: See Company Schedule E-1 Line 13. The Company's accrued allowance for Doubtful Accounts increased from $(366,736) at December 31, to $(1,219,587) on June 30, 2008. In order to reduce this accelerating increase in accrued bad debt, the uncollectibles rate is being reduced from .487% to .3468% so that the over accrual. will be eliminated in three years leaving a 100% reserve at the end of three years.
B: Company bad debt pro forma adjustment detail spreadsheet.

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Fuel Expense Adjustment
Test Yeat Ended June 30, 2008

LINE NO.	DESCRIPTION		AMOUNT	REFERENCE
1	Total Miles		2,960,186	Data Request Resp THF 8.10
2	Average Price/Gallon	$	3.35	Data Request Resp THF 8.10
3	Total Gallons		222,973	Data Request Resp THF 8.10
4	Total Cost	$	745,346	Data Request Resp THF 8.10
5	Average Price/Gallon '09	$	1.96	Energy Information Admin
6	Total Cost @ '09 price	$	450,747	Line 5 * Line 3
7	Adjustment	$	(294,599)	Line 6 - Line 4

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Postage Expense Adjustment
Test Yeat Ended June 30, 2008

LINE NO.	DESCRIPTION		AMOUNT	REFERENCE
1	Number of Customer Bills		1,739,076	Co. Schedule H-2
2	Increase in Postage Rates '09		$0.02	
3	09 increase in postage rates/Company cust	$	34,782	Line 1 * Line 2
4	Staff Customer Annualization		34,440	Staff Schedule THF - C.1a
5	Staff Customer Annualization Postage	$	15,154	Line 4 * .44
6	Postage Expense Adjustment	$	49,594	Line 3 * Line 5

UNS Gas, Inc.
Docket No. G-04204A-08-0571
AGA Dues Adjustment
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION	TEST YEAR 06 AMOUNT	TEST YEAR 06/30/08 AMOUNT	REFERENCE
1	AGA Dues	$ 43,377	$ 45,964	A
2	Percentage Disallowance	3.511%	3.511%	B
3	Disallowance	$ 1,523	$ 1,614	C
4	Adjustment		$ (1,614)	

Source:
A: Company Filings
B: Disallowance percentage Decision 70011
C: Line 1 * Line 2

UNS Gas, Inc.
Docket No. G-04204A-08-057
Legal Expenses Adjustment
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION		AMOUNT	REFERENCE
1	Company pro forma Adjustment	$	305,984	Company Schedule C.2 p. 4 of 4
2	Adjustment	$	(305,984)	

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Call Center Expense Adjustment
Test Year Ended June 30, 2008

LINE NUMBER	DESCRIPTION		AMOUNT	REFERENCE
1	Average Monthly Allocation 2005	$	76,227	A
2	Total Call Center Allocation 2005	$	914,724	Line 1 * 12
3	Total Call Center Allocation - Test Year	$	1,399,522	DR Response THF 8.4
4	Adjustment	$	(484,798)	Line 2 - Line 3

Source:
A: UNS Decision 70011

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Interest Synchronization
Test Year Ended June 30, 2008

Test Year Ended June 30, 2008		Amount	Reference
A.	Adjusted Rate Base	$178,576,365	1
B.	Weighted cost of Debt	3.24%	2
C.	Synchronized Interest Deduction	$5,785,874	A x B
D.	Synchronized Interest Deduction per UNS Gas	$5,924,526	3
E.	Difference increased interest deduction	$138,652	C - D
F.	Combined Federal and State Income Tax Rates	39.60%	4
G.	Increase to Income Tax Expense	$54,906	E x F

Sources
1. Schedule B-1, Page 1 of 1, Line 18
2. Schedule D-1, Page 1 of 2, Line 2
3. Schedule B-5, Page 3 of 3, Line 18
4. Schedule G-4, Page 26 of 30, Line 25+29

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Intercompany Incentive Compensation Adjustment PEP
Test Year Ended June 30, 2008

		A		B	C	
LINE NO.	DESCRIPTION		COMPANY AMOUNT	DISALLOWANCE PERCENTAGE		STAFF ADJUSTED AMOUNT
1	Incentive Comp TY end June '08	$	125,492	50.00%	$	62,746
2	Executive Comp and Bene TY 6/08	$	109,295	50.00%	$	54,648
3	Total	$	234,787	50.00%	$	(117,394)

Source:

A: Data Request response THF 8.4
B: From Decision 70011
C: Column A * Column B

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Intercompany Incentive Compensation Adjustment SERP
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION		AMOUNT	REFERENCE
1	SERP Amount	$	310,278	From Company Workpapers
2	SERP Adjustment	$	(310,412.00)	Decision 70011

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Payroll tax expense, PEP incentive
Test Year Ended June 30, 2008

LINE NO.	DESCRIPTION		AMOUNT	REFERENCE
1	PEP Incentive Disallowance	$	117,393	Schedule THF - C.12
2	Payroll tax expense PEP	$	11,739	10%
3	Adjustment	$	11,739	

CORRECTED PRO FORMA ADJUSTMENT FOR STAFF DATA REQUEST TF 6.68

ADJUSTMENT NAME:	Rate Case Expense
ADJUSTMENT TO:	Income Statement
DATE SUBMITTED:	April 8, 2009
PREPARED BY:	Janet Zaidenberg-Schrum
CHECKED BY:	Mina Briggs
REVIEWED BY:	Dallas Dukes

FERC ACCT	FERC ACCOUNT DESCRIPTION	DEBIT	CREDIT
928	Regulatory Expense (A)	$33,333	
928	Regulatory Expense (B)	$166,667	
407	**Amortization of Regulatory Assets - Rate Case Expense**		**$58,333**
	ENTRY TOTAL	**$200,000**	**$58,333**
	NET ENTRY	**$141,667**	

Reason for Adjustment

A) To include rate case expense approved in ACC Decision No. 70011 for the 2006 rate case.

B) To include an estimate of outside expenditures for the rate case expense amortization for $500,000 total expense amortized over 3 years @ $166,667 per year.

Addition to Original Pro Forma to correct test year expense

C) To remove test year amortization of rate case expense for $200,000 of the $300,000 allowed in ACC Decision No. 70011 for the 2006 rate case that will be recovered prior to new rates becoming effective.

Note: Pro forma adjustments related to the write-off 2006 rate case expense not included in the $300,000 allowed in ACC Decision No. 70011 are included in the pro forma adjustment for Miscellaneous Expenses.

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Customer Class Risk Analysis
Test Yeat Ended June 30, 2009

LINE NO.	DESCRIPTION	Coefficient of Variation Decatherms Time Series, TSCI TSCI/TS	Raw Data
1	Residential Service	14.614	74.847
2	Commercial Gas Service	13.317	49.772
3	Industrial Gas Service	36.713	43.804
4	Public Authority Gas Servic	14.686	78.205
5	Total Company	13.497	66.988

References:
Coefficient of Variation = Standard Deviation/Mean

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Summary of Revenues by Customer Class
Adjusted Present Rates and Proposed Rates
Test Yeat Ended June 30, 2010

LINE NO.	DESCRIPTION	(A) COMPANY PRESENT NET REVENUE	(B) COMPANY PROPOSED NET REVENUE	(C) COMPANY PROPOSED NET INCREASE	(D) COMPANY PROPOSED % INCREASE	(E) STAFF PRESENT NET REVENUE	(F) STAFF PROPOSED NET REV	(G) STAFF PROPOSED NET INCRSE	(H) STAFF PROPOSED % INCRSE
1	Residential Service	$ 36,381,453	$ 43,056,622	$ 6,675,169	18.348%	$ 37,432,308	$ 39,777,559	$ 2,345,251	6.265%
2	Commercial Gas Service	$ 9,818,220	$ 11,689,364	$ 1,871,144	19.058%	$ 10,302,730	$ 10,927,395	$ 624,665	6.063%
3	Industrial Gas Service	$ 255,152	$ 303,253	$ 48,101	18.852%	$ 186,135	$ 278,720	$ 92,585	49.741%
4	Public Authority Gas Service	$ 1,779,079	$ 2,117,900	$ 338,821	19.045%	$ 1,812,092	$ 1,961,563	$ 149,471	8.249%
5	Special Gas Light Service	$ 66,940	$ 79,706	$ 12,766	19.071%	$ 66,940	$ 71,107	$ 4,167	6.225%
6	Irrigation Service	$ 33,865	$ 40,322	$ 6,457	19.067%	$ 33,865	$ 35,972	$ 2,107	6.222%
7	Transportation Customers	$ 2,823,056	$ 3,351,473	$ 528,417	18.718%	$ 2,823,066	$ 2,999,243	$ 176,177	6.241%
8	Subtotal	$ 51,157,765	$ 60,638,640	$ 9,480,875	18.533%	$ 52,657,136	$ 56,051,559	$ 3,394,423	6.446%
9	Other Operating Revenue	$ 1,744,743	$ 1,744,743	$ -	0.000%	$ 1,744,743	$ 1,744,743	$ -	0.000%
10	Total	$ 52,902,508	$ 62,383,383	$ 9,480,875	17.921%	$ 54,401,879	$ 57,796,302	$ 3,394,423	6.240%

References:
Columns (A), (B), (C) and (D) Company H-2(P2)

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Comparison of Revenues by Rate Schedules
Adjusted Present Rates and Proposed Rates
Test Yeat Ended June 30, 2010

LINE NO.	DESCRIPTION	(A) COMPANY ADJUSTED NET REVENUE	(B) COMPANY PROPOSED INCREASE	(C) COMPANY PROPOSED NET REVENUE	(D) STAFF ADJUSTED NET REVENUE	(E) STAFF PROPOSED INCREASE	(F) STAFF PROPOSED NET REVENUE
1	Residential Service	$ 35,003,749	$ 6,675,169	$ 41,678,918	$ 36,125,387	$ 2,335,687	$ 38,461,074
2	Residential Service - CARES	$ 1,377,705	$ -	$ 1,377,705	$ 1,306,921	$ -	$ 1,306,921
3	Small volume commercial	$ 9,571,509	$ 1,825,274	$ 11,396,783	$ 10,030,325	$ 614,202	$ 10,644,527
4	Large volume commercial	$ 246,710	$ 45,870	$ 292,580	$ 272,405	$ 16,681	$ 289,086
5	Commercial Transportation	$ 533,224	$ 102,862	$ 636,086	$ 533,221	$ 33,607	$ 566,828
6	Small volume industrial	$ 133,707	$ 25,498	$ 159,205	$ 91,458	$ 45,959	$ 137,417
7	Large volume industrial	$ 121,445	$ 22,603	$ 144,048	$ 94,650	$ 47,548	$ 142,198
8	Industrial transportation	$ 1,118,256	$ 213,806	$ 1,332,062	$ 1,118,216	$ 70,479	$ 1,188,695
9	Industrial transportation - contracts	$ 451,464	$ 86,094	$ 537,558	$ 451,408	$ 28,451	$ 479,859
10	T2 Transportation	$ 63,852	$ 80	$ 63,932	$ 65,777	$ 4,146	$ 69,923
11	Small volume public authority	$ 1,630,262	$ 310,889	$ 1,941,151	$ 1,660,873	$ 138,353	$ 1,799,226
12	Large volume public authority	$ 148,817	$ 27,932	$ 176,749	$ 151,219	$ 12,605	$ 163,824
13	Public Authority Transportation	$ 656,260	$ 125,595	$ 781,855	$ 654,471	$ 41,369	$ 695,840
14	Special gas light services	$ 66,940	$ 12,766	$ 79,706	$ 66,940	$ 4,208	$ 71,148
15	Irrigation service	$ 33,865	$ 6,458	$ 40,323	$ 33,865	$ 2,128	$ 35,993
16	Total gas service	$ 51,157,765	$ 9,480,896	$ 60,638,661	$ 52,657,136	$ 3,395,423	$ 56,052,559

References:
Columns (A), (B), (C) and (D) Company H-2(P2)

UNS Gas, Inc.
Docket No. G-04204A-08-0571
Summary of Staff Recommended Rate Design
Test Yeat Ended June 30, 2009

LINE NO.	CLASS OF SERVICE	Current Rates	Proposed Rates	Change
1	**Residential Service R(10)**			
2	Customer Charge	$8.5000	$9.5000	$1.0000
3	Distribution Margin Therms	$0.3270	$0.3383	$0.0113
4	**Small Commercial Service (C20)**			
5	Customer Charge	$13.5000	$15.5000	$2.0000
6	Distribution Margin Therms	$0.2638	$0.2746	$0.0108
7	**Large Commercial Service (C22)**			
8	Customer Charge	$100.0000	$105.0000	$5.0000
9	Distribution Margin Therms	$0.1718	$0.1825	$0.0107
10	**Small Volume Industrial Service (I-30)**			
11	Customer Charge	$13.5000	$15.5000	$2.0000
12	Distribution Margin Therms	$0.2356	$0.2556	$0.0200
13	**Large Volume Industrial Service (I-32)**			
14	Customer Charge	$100.0000	$105.0000	$5.0000
15	Distribution Margin Therms	$0.0952	$0.1152	$0.0200
16	**Small Volmune PA ((PA-40)**			
17	Customer Charge	$13.5000	$15.5000	$2.0000
18	Distribution Margin Therms	$0.2593	$0.2789	$0.0196
19	**Large Volume PA (PA-42)**			
20	Customer Charge	$100.0000	$105.0000	$5.0000
21	Distribution Margin Therms	$0.1198	$0.1300	$0.0102
22	**Special Gas Light Service (PA-44)**			
23	Single Office	$23.7200	$23.0100	-$0.7100
24	Double Office	$39.5300	$40.7200	$1.1900
25	Triple Office	$54.8600	$58.1000	$3.2400
26	Quadruple Office	$71.1800	$76.1400	$4.9600
27	**Irrigation Service (IR-60)**			
28	Customer Charge	$13.5000	$15.5000	$2.0000
29	Distribution Margin Therms	$0.3192	$0.3386	$0.0194

S Gas, Inc.
G-04204A-08-0571
f of Revenue
nded June 30, 2010

Line No.	Description	Element	Present Rates	Billing Units	Adjusted Present Revenue	Proposed Rates	Proposed Revenue
1	Residential R10	Customer Charge	$8.5000	1,537,340	$13,067,390.00	$9.5000	$14,604,730.00
2		Distribution Margin	$0.3270	70,513,752	$23,057,996.90	$0.3383	$23,856,344.00
3					$36,125,386.90		$38,461,074.00
4	Residential R12	No change	No change	81,660	$1,306,921.00		$1,306,921.00
5	Small Commercial C-20	Customer Charge	$13.5000	140,430	$1,895,805.00	$15.5000	$2,176,665.00
6		Distribution Margin	$0.2638	30,835,936	$8,134,519.92	$0.2746	$8,467,862.00
7					$10,030,324.92		$10,644,527.00
8	Large Commercial C-22	Customer Charge	$100.0000	219	$21,900.00	$105.0000	$22,995.00
9		Distribution Margin	$0.1718	1,458,120	$250,505.02	$0.1825	$266,091.00
10					$272,405.02		$289,086.00
11	Small Industrial I-30	Customer Charge	$13.5000	240	$3,240.00	$15.5000	$3,720.00
12		Distribution Margin	$0.2356	523,052	$88,218.06	$0.2556	$133,692.00
13					$91,458.06		$137,412.00
14	Large Industrial I-32	Customer Charge	$100.0000	73	$7,300.00	$105.0000	$7,665.00
15		Distribution Margin	$0.0952	1,167,821	$87,350.00	$0.1152	$134,533.00
16					$94,650.00		$142,198.00
17	Smal Public Authority PA-40	Customer Charge	$13.5000	12,925	$174,487.50	$15.5000	$200,337.50
18		Distribution Margin	$0.2593	5,732,300	$1,486,385.39	$0.2789	$1,598,888.50
19					$1,660,872.89		$1,799,226.00
20	Large Public Authority PA-42	Customer Charge	$100.0000	60	$6,000.00	$105.0000	$6,300.00
21		Distribution Margin	$0.1198	1,212,179	$145,219.04	$0.1300	$157,524.00
22					$151,219.04		$163,824.00
23	Gas Lighting PA-44		$18.1100	3,696	$66,934.56	$19.2500	$71,148.00
24	Large Industrial I-32	Customer Charge	$13.5000	60	$810.00	$15.5000	$930.00
25		Distribution Margin	$0.3192	103,554	$33,054.44	$0.3386	$35,063.00
26					$33,864.44		$35,993.00

UNS Gas, Inc.
Docket No. G-04024A-08-0571
Typical Bill Comparison
Test Year Ended June 30,2008

Residential Service R10		
Customer Charge	$8.50	$9.50
Distribution Margin Therms	$0.3270	$0.3383

Average Therms Per Month	Total Bill Present Rates	Total Bill Proposed Rates	Proposed Increase $	Proposed Increase %
5	$10.14	$11.19	$1.06	10.424%
10	$11.77	$12.88	$1.11	9.456%
20	$15.04	$16.27	$1.23	8.152%
35	$19.95	$21.34	$1.40	6.997%
50	$24.85	$26.42	$1.57	6.298%
75	$33.03	$34.87	$1.85	5.594%
100	$41.20	$43.33	$2.13	5.170%
250	$90.25	$94.08	$3.83	4.238%
500	$172.00	$178.65	$6.65	3.866%

Small Commercial Service C20		
Customer Charge	$13.50	$15.50
Distribution Margin Therms	$0.2638	$0.2746

Average Therms Per Month	Total Bill Present Rates	Total Bill Proposed Rates	Proposed Increase $	Proposed Increase %
50	$26.69	$29.23	$2.54	9.517%
100	$39.88	$42.96	$3.08	7.723%
500	$145.40	$152.80	$7.40	5.089%
1000	$277.30	$290.10	$12.80	4.616%
1500	$409.20	$427.40	$18.20	4.448%
2500	$673.00	$702.00	$29.00	4.309%
5000	$1,332.50	$1,388.50	$56.00	4.203%
7500	$1,992.00	$2,075.00	$83.00	4.167%
1000	$277.30	$290.10	$12.80	4.616%

Large Commercial Service C22

Customer Charge	$100.00	$105.00
Distribution Margin Therms	$0.1718	$0.1825

Average Therms Per Month	Total Bill Present Rates	Total Bill Proposed Rates	Proposed Increase $	Proposed Increase %
10001	$1,818.17	$1,930.18	$112.01	6.161%
12500	$2,247.50	$2,386.25	$138.75	6.174%
17500	$3,106.50	$3,298.75	$192.25	6.189%
20000	$3,536.00	$3,755.00	$219.00	6.193%
25000	$4,395.00	$4,667.50	$272.50	6.200%
30000	$5,254.00	$5,580.00	$326.00	6.205%
45000	$7,831.00	$8,317.50	$486.50	6.212%
75000	$12,985.00	$13,792.50	$807.50	6.219%

Small Volume Industrial Service I30

Customer Charge	$13.50	$15.50
Distribution Margin Therms	$0.2356	$0.2556

Average Therms Per Month	Total Bill Present Rates	Total Bill Proposed Rates	Proposed Increase $	Proposed Increase %
50	$25.28	$28.28	$3.00	11.867%
100	$37.06	$41.06	$4.00	10.793%
500	$131.30	$143.30	$12.00	9.139%
1000	$249.10	$271.10	$22.00	8.832%
1500	$366.90	$398.90	$32.00	8.722%
2500	$602.50	$654.50	$52.00	8.631%
5000	$1,191.50	$1,293.50	$102.00	8.561%
7500	$1,780.50	$1,932.50	$152.00	8.537%
10000	$2,369.50	$2,571.50	$202.00	8.525%

UNS Gas, Inc.
Docket No. G-04024A-08-0571
Typical Bill Comparison
Test Year Ended June 30,2008

Large Volume Industrial Service I32		
Customer Charge	$100.00	$105.00
Distribution Margin Therms	$0.0952	$0.1152

Average Therms Per Month	Total Bill Present Rates	Total Bill Proposed Rates	Proposed Increase $	Proposed Increase %
10001	$1,052.10	$1,257.12	$205.02	19.487%
12500	$1,290.00	$1,545.00	$255.00	19.767%
17500	$1,766.00	$2,121.00	$355.00	20.102%
20000	$2,004.00	$2,409.00	$405.00	20.210%
25000	$2,480.00	$2,985.00	$505.00	20.363%
30000	$2,956.00	$3,561.00	$605.00	20.467%
45000	$4,384.00	$5,289.00	$905.00	20.643%
75000	$7,240.00	$8,745.00	$1,505.00	20.787%

Small Volume Public Authority PA40		
Customer Charge	$13.50	$15.50
Distribution Margin Therms	$0.2593	$0.2789

Average Therms Per Month	Total Bill Present Rates	Total Bill Proposed Rates	Proposed Increase $	Proposed Increase %
50	$26.47	$29.45	$2.98	11.260%
100	$39.43	$43.39	$3.96	10.043%
500	$143.15	$154.95	$11.80	8.243%
1000	$272.80	$294.40	$21.60	7.918%
1500	$402.45	$433.85	$31.40	7.802%
2500	$661.75	$712.75	$51.00	7.707%
5000	$1,310.00	$1,410.00	$100.00	7.634%
7500	$1,958.25	$2,107.25	$149.00	7.609%
1000	$272.80	$294.40	$21.60	7.918%

Large Public Authority Service PA42		
Customer Charge	$100.00	$105.00
Distribution Margin Therms	$0.1198	$0.1300

Average Therms Per Month	Total Bill Present Rates	Total Bill Proposed Rates	Proposed Increase $	Proposed Increase %
10001	$1,298.12	$1,405.13	$107.01	8.243%
12500	$1,597.50	$1,730.00	$132.50	8.294%
17500	$2,196.50	$2,380.00	$183.50	8.354%
20000	$2,496.00	$2,705.00	$209.00	8.373%
25000	$3,095.00	$3,355.00	$260.00	8.401%
30000	$3,694.00	$4,005.00	$311.00	8.419%
45000	$5,491.00	$5,955.00	$464.00	8.450%
75000	$9,085.00	$9,855.00	$770.00	8.476%

Irrigation Service IR60		
Customer Charge	$13.50	$15.50
Distribution Margin Therms	$0.3192	$0.3386

Average Therms Per Month	Total Bill Present Rates	Total Bill Proposed Rates	Proposed Increase $	Proposed Increase %
50	$29.46	$32.43	$2.97	10.081%
100	$45.42	$49.36	$3.94	8.675%
500	$173.10	$184.80	$11.70	6.759%
1000	$332.70	$354.10	$21.40	6.432%
1500	$492.30	$523.40	$31.10	6.317%
2500	$811.50	$862.00	$50.50	6.223%
5000	$1,609.50	$1,708.50	$99.00	6.151%
7500	$2,407.50	$2,555.00	$147.50	6.127%
10000	$3,205.50	$3,401.50	$196.00	6.114%

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-08-0571

DIRECT

TESTIMONY

OF

DAVID C. PARCELL

ON BEHALF OF THE

UTILITIES DIVISION STAFF

ARIZONA CORPORATION COMMISSION

JUNE 08, 2009

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ATTACHMENTS

DAVID C. PARCELL RESUME .... ATTACHMENT 1

SCHEDULES

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I. INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is David C. Parcell. I am President and Senior Economist of Technical Associates, Inc. My business address is Suite 601, 1051 East Cary Street, Richmond, Virginia 23219.

Q. Please summarize your educational background and professional experience.

A. I hold B.A. (1969) and M.A. (1970) degrees in economics from Virginia Polytechnic Institute and State University (Virginia Tech) and a M.B.A. (1985) from Virginia Commonwealth University. I have been a consulting economist with Technical Associates since 1970. I have provided cost of capital testimony in public utility ratemaking proceedings, dating back to 1972. In connection with this, I have previously filed testimony and/or testified in over 430 utility proceedings before about more than 40 regulatory agencies in the United States and Canada. Attachment 1 provides a more complete description of my education and relevant work experience.

Q. What is the purpose of your testimony in this proceeding?

A. I have been retained by the Utilities Division Staff to evaluate the cost of capital aspects of the current filing of UNS Gas, Inc. ("UNS Gas" or "Company"). I have performed independent studies and am making recommendations of the current cost of capital for UNS Gas. In addition, since UNS Gas is a subsidiary of UniSource Energy Corporation ("UniSource"), I have also evaluated UniSource in my analyses.

Q. Have you prepared an exhibit in support of your testimony?

A. Yes, I have prepared one exhibit, made up of 14 Schedules, identified as Schedule 1 through Schedule 14. These Schedules were prepared either by me or under my direction. The information contained in these schedules is correct to the best of my knowledge and belief.

II. RECOMMENDATIONS AND SUMMARY

Q. What are your recommendations in this proceeding?

A. My overall cost of capital recommendations for UNS Gas are:

	Percent	Cost	Return
Long-Term Debt	50.01%	6.49%	3.25%
Common Equity	49.99%	9.5-10.5%	4.75-5.25%
Total	100.00%		7.99-8.49%
			8.24% mid-point

UNS Gas' application requests a return on common equity of 11.0 percent and overall rate of return of 8.75 percent. I propose a return on common equity of 10.0 percent and an overall rate of return of 8.24 percent.

Q. Please summarize your cost analyses and related conclusions for UNS Gas.

A. This proceeding is concerned with UNS Gas' regulated natural gas utility operations in Arizona. My analyses are concerned with the Company's total cost of capital. The first step in performing an analysis of the Company's cost of capital is the development of the appropriate capital structure. UNS Gas' proposed capital structure is comprised of 49.99

percent common equity and 50.01 percent long-term debt. This capital structure is the June 30, 2008 test period capital structure of the Company. I also use this same capital structure in my cost of capital analyses.

The second step in a cost of capital calculation is a determination of the embedded cost rate of debt. UNS Gas' application uses a cost rate of 6.49 percent, which reflects the Company's cost at June 30, 2008. I have used the same rate for this item as is proposed by the Company.

The third step in the cost of capital calculation is the estimation of the cost of common equity. I have employed three recognized methodologies to estimate the cost of equity for UNS Gas. Each of these methodologies is applied to two groups of proxy utilities. These three methodologies and my findings are:

Methodology	Range
Discounted Cash Flow	9.5-10.5%
Capital Asset Pricing Model	7.3-7.8%
Comparable Earnings	9.5-10.5%

Based upon these findings, I conclude that the cost of common equity for UNS Gas is within a range of 9.5 percent to 10.5 percent. I recommend the mid-point of my cost of equity range (10.0 percent), which is the same cost of equity approved by the Commission in UNS Gas' last rate case. There is no indication that UNS Gas' level of risk has increased since the last proceeding. In addition, there are indications that capital costs have declined since the last case. Finally, the current economic recession should have the effect of lowering the cost of equity. In any event, the impact of declining economic circumstances has negative effects on all of UNS Gas' customers (residential, commercial, and industrial) – there is no justification for increasing UNS Gas' profit level as the same time that virtually all of its customers has suffering from lower incomes/profits.

Combining these three steps into a weighted cost of capital results in an overall rate of return range of 7.99 percent to 8.49 percent. My recommended 10.0 percent cost of equity results in an overall cost of capital of 8.24 percent.

III. ECONOMIC/LEGAL PRINCIPLES AND METHODOLOGIES

Q. What are the primary economic and legal principles that establish the standards for determining a Fair Rate of Return for a regulated utility?

A. Public utility rates are normally established in a manner designed to allow the recovery of their costs, including capital costs. This is frequently referred to as "cost of service" ratemaking. Rates for regulated public utilities traditionally have been primarily established using the "rate base - rate of return" concept. Under this method, utilities are allowed to recover a level of operating expenses, taxes, and depreciation deemed reasonable for rate-setting purposes, and are granted an opportunity to earn a fair rate of return on the assets used and useful (*i.e.*, rate base) in providing service to their customers.

The rate base is derived from the asset side of the utility's balance sheet as a dollar amount and the rate of return is developed from the liabilities/owners' equity side of the balance sheet as a percentage. The revenue impact of the cost of capital is thus derived by multiplying the rate base by the rate of return (including income taxes).

The rate of return is developed from the cost of capital, which is estimated by weighting the capital structure components (i.e., debt, preferred stock, and common equity) by their percentages in the capital structure and multiplying these by their cost rates. This is also known as the weighted cost of capital.

Technically, "fair rate of return" is a legal and accounting concept that refers to an *ex post* (after the fact) earned return on an asset base, while the cost of capital is an economic and financial concept which refers to an *ex ante* (before the fact) expected or required return on a liability base. In regulatory proceedings, however, the two terms are often used interchangeably, as I have done in my testimony.

From an economic standpoint, a fair rate of return is normally interpreted to mean that an efficient and economically managed utility will be able to maintain its financial integrity, attract capital, and establish comparable returns for similar risk investments. These concepts are derived from economic and financial theory and are generally implemented using financial models and economic concepts.

Although I am not a lawyer and I do not offer a legal opinion, my testimony is based on my understanding that two United States Supreme Court decisions provide the main standards for a fair rate of return. The first decision is Bluefield Water Works and Improvement Co. v. Public Serv. Comm'n of West Virginia, 262 U.S. 679 (1923). In this decision, the Court stated:

> What annual rate will constitute **just compensation** depends upon many circumstances and must be **determined by** the **exercise of fair and enlightened judgment**, having regard to all relevant facts. A public utility is entitled to such rates as will permit it to **earn a return** on the value of the property which it employs for the convenience of the public equal to that **generally being made** at the same time and in the same general part of the country on **investments in other business undertakings** which are **attended by corresponding risks and uncertainties**; but it has no **constitutional right to profits** such as are realized or anticipated in **highly profitable enterprises or speculative ventures**. The **return** should be reasonably sufficient to assure confidence in the **financial soundness** of the utility, and should be adequate, **under efficient and economical management**, to maintain and **support its credit** and **enable it to raise the money** necessary for the proper discharge of its public duties. A rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally. **[Emphasis added.]**

It is my understanding that the Bluefield decision established the following standards for a fair rate of return: comparable earnings, financial integrity, and capital attraction. It also noted the changing level of required returns over time as well as an underlying assumption that the utility be operated in an efficient manner.

The second decision is Federal Power Comm'n v. Hope Natural Gas Co., 320 U.S. 591 (1942). In that decision, the Court stated:

> The rate-making process under the [Natural Gas] Act, i.e., the fixing of 'just and reasonable' rates, involves a balancing of the **investor** and **consumer interests** . . . . From the investor or company point of view it is important that there be enough revenue not only for operating expenses but also for the capital costs of the business. These include service on the debt and dividends on the stock. By that standard the **return** to the equity **owner** should be **commensurate** with **returns** on **investments** in **other enterprises having corresponding risks**. That return, moreover, should be sufficient to assure confidence in the **financial integrity** of the enterprise, so as to **maintain its credit** and to **attract capital**. **[Emphasis added.]**

The Hope case is also frequently credited with establishing the "end result" doctrine, which maintains that the methods utilized to develop a fair return are not important as long as the end result is reasonable.

The three economic and financial parameters in the Bluefield and Hope decisions - comparable earnings, financial integrity, and capital attraction - reflect the economic criteria encompassed in the "opportunity cost" principle of economics. The opportunity cost principle provides that a utility and its investors should be afforded an opportunity (not a guarantee) to earn a return commensurate with returns they could expect to achieve on investments of similar risk. The opportunity cost principle is consistent with the fundamental premise, on which regulation rests, namely, that it is intended to act as a surrogate for competition.

I understand that because Arizona is a "Fair Value" state, Hope and Bluefield do not set forth the legal requirements applicable to determining fair rate of return in Arizona. In Simms v. Round Valley Light & Power Company, 294 P.2d 378 (1956) the Arizona Supreme Court took exception to application of the following principle in Arizona since the Constitution mandates consideration of fair value:

> "In the Hope case the court, in testing the reasonableness of rates fixed by the Federal Power Commission under the Natural Gas Act, 15 U.S.C.A. Section 717 et seq., after holding that congress had provided no formula by which just and reasonable rates were to be determined, ruled that it was the final result reached and not the method used in reaching the result that was controlling and that it was unimportant to 'determine the various permissible ways in which any rate base on which the return in computed might be arrived at."

My testimony does not advocate that the Commission ignore the Simms holding in this regard, or the fair value of UNS Gas' property, which it is required to consider under Article 15, Section of the Arizona Constitution. Rather, I find the Hope and Bluefield decisions can be helpful in their discussion of comparable earnings, financial integrity and capital attraction. I note that UNS Gas Witness Grant also cites the Hope and Bluefield cases as guidelines for evaluating the cost of capital for the Company.

Q. How can these parameters be employed to estimate the cost of capital for a utility?

A. Neither the courts nor economic/financial theory have developed exact and mechanical procedures for precisely determining the cost of capital. This is the case because the cost of capital is an opportunity cost and is prospective-looking, which dictates that it must be estimated.

There are several useful models that can be employed to assist in estimating the cost of equity capital, which is the capital structure item that is the most difficult to determine. These include the Discounted Cash Flow ("DCF"), Capital Asset Pricing Model ("CAPM"), Comparable Earnings ("CE") and Risk Premium ("RP") methods. Each of these methods (or models) differs from the others and each, if properly employed, can be a useful tool in estimating the cost of common equity for a regulated utility.

Q. Which methods have you employed in your analyses of the cost of common equity in this proceeding?

A. I have utilized three methodologies to determine UNS Gas' cost of common equity: the DCF, CAPM, and CE methods. I have not employed a RP model in my analyses although, as I indicate later, my CAPM analysis is a form of the RP methodology. Each of these methodologies will be described in more detail in my testimony that follows.

IV. GENERAL ECONOMIC CONDITIONS

Q. Why are economic and financial conditions important in determining the costs of capital?

A. The costs of capital, for both fixed-cost (debt and preferred stock) components and common equity, are determined in part by current and prospective economic and financial conditions. At any given time, each of the following factors has an influence on the costs of capital: the level of economic activity (i.e., growth rate of the economy), the stage of the business cycle (i.e., recession, expansion, or transition), the level of inflation, and expected economic conditions. My understanding is that this position is consistent with the Bluefield decision that noted "[a] rate of return may be reasonable at one time, and become too high or too low by changes affecting opportunities for investment, the money market, and business conditions generally."

Q. What indicators of economic and financial activity have you evaluated in your analyses?

A. I have examined several sets of economic statistics from 1975 to the present. I chose this time period because it permits the evaluation of economic conditions over three full business cycles plus the current cycle to date, allowing for an assessment of changes in long-term trends. This period also approximates the beginning and continuation of active rate case activities by public utilities.

A business cycle is commonly defined as a complete period of expansion (recovery and growth) and contraction (recession). A full business cycle is a useful and convenient period over which to measure levels and trends in long-term capital costs because it incorporates the cyclical (i.e., stage of business cycle) influences, and thus, permits a comparison of structural (or long-term) trends.

Q. Please describe the timeframe of the three prior business cycles and the most recent cycle.

A. The three prior complete cycles and most recent cycle cover the following periods:

Business Cycle	Expansion Cycle	Contraction Period
1975-1982	Mar. 1975-July 1981	Aug. 1981-Oct. 1982
1982-1991	Nov. 1982-July 1990	Aug. 1990-Mar. 1991
1991-2001	Apr. 1991-Mar. 2001	Apr. 2001-Nov. 2001
Current	Dec. 2001-Nov. 2007	Dec. 2007-Present

Source: National Bureau of Economic, Research, "Business Cycle Expansions and Contractions."

Q. Do you have any general observations concerning the recent trends in economic conditions and their impact on capital costs over this broad period?

A. Yes, I do. As I will describe below, until recently the U.S. economy enjoyed general prosperity and stability over the period since the early 1980s. This period has been characterized by longer economic expansions, relatively tame contractions, relatively low and declining inflation, and declining interest rates and other capital costs. The current business cycle began in late 2001, following a somewhat modest recession earlier in the year.

Over the past two years, on the other hand, the economy has declined significantly, initially as a result of the 2007 collapse of the "sub-prime" mortgage market and related liquidity crises in the financial sector of the economy. Subsequently, this financial crisis intensified with a more broad-based decline initially based on a significant increase in petroleum prices and an increasing decline in the U.S. financial sector culminating with the collapse and/or bailouts of a substantial number of long-standing institutions such as Bear Stearns, Lehman Brothers, Merrill Lynch, Freddie Mac, Fannie Mae, AIG and Wachovia. This crisis has been described as the worst financial crisis since the Great Depression. The U.S. and global governments are in the process of implementing unprecedented actions to attempt to correct or minimize its scope and effects. As of this time, the consequences of these governmental initiatives are unclear. There is also a universal acceptance that the economy is in a serious recession. The impacts of a severe recession on cost of capital is very likely to be characterized by lower utility growth and declining capital costs due to a decline in corporate profits and expected earnings growth. It is clear that a serious recession also has negative impacts on UNS Gas' customers, in terms of income levels, unemployment and higher poverty levels. In addition, it is likely that UNS Gas' business customers are experiencing lower profits as a result of the recession. Clearly, this is not an environment in which it is sensible to increase the profitability of a regulated company such as UNS Gas.

Q. Please describe recent and current economic and financial conditions and their impact on the costs of capital.

A. Schedule 2 shows several sets of economic data. Pages 1 and 2 contain general macroeconomic statistics while pages 4 through 6 contain financial market statistics. Pages 1 and 2 show that the U.S. economy ended 2007 as the sixth year of an economic expansion although, as indicated previously, the economy was then entering a decline. This is indicated by the growth in real (i.e., adjusted for inflation) Gross Domestic Product ("GDP"), industrial production, and the increase in the unemployment rate. This most recent expansion was characterized by slower growth, in comparison to prior expansions which resulted in lower inflationary pressures and interest rates.

The rate of inflation is also shown on pages 1 and 2. As is reflected in the Consumer Price Index ("CPI"), for example, inflation rose significantly during the 1975-1982 business cycle and reached double-digit levels in 1979-1980. The rate of inflation declined substantially in 1981 and remained at or below 6.1 percent during the 1983-1991 business cycle. Since 1991, the CPI has been 4.1 percent or lower. The 0.1 percent rate of inflation in 2008 was the lowest level of the past thirty years. This is indicative of virtually no inflation, which should also be reflective of lower capital costs.

Q. What have been the trends in interest rates?

A. Pages 3 and 4 show several series of interest rates. Rates rose sharply to record levels in 1975-1981 when the inflation rate was high and generally rising. Interest rates declined substantially in conjunction with inflation rates throughout the remainder of the 1980s and throughout the 1990s. Interest rates declined even further from 2000-2005 and generally recorded their lowest levels since the 1960s.

During the past several years and up until the later half of 2008, long-term interest rates remained low by historic standards. During the 2001 recession and early in the succeeding expansion, the Federal Reserve lowered interest rates (i.e., Federal Funds rate) 11 times in 2001 and twice in 2003 in an effort to stimulate the economy. Following this, the Federal Reserve increased short-term interest rates on 17 occasions between 2004 and 2006,[1] although each time by only 0.25 percent, in an attempt to ensure that any perceived inflationary expectations will not stifle continued economic growth. Nevertheless, the Federal Reserve actions did not result in a pronounced increase in long-term rates. Most recently, however, the Federal Reserve has lowered the

[1] See Federal Reserve Bank of New York, "Historical Changes of the Target Federal Funds and Discount Rates," www.newyorkfed.org/markets/statistics/dlyrates/fedrate.html.

Federal Funds rate (i.e., short-term rate) on several occasions and it is currently 0.25 percent, an all-time low. The year 2008 experienced a pronounced decline in short-term rates and long-term U.S. Treasury Securities yields, and an increase in utility bond yields.

Q. What have been the trends in common share prices?

A. Pages 5 and 6 show several series of common stock prices and ratios. These ratios indicate that share prices were essentially stagnant during the high inflation/interest rate environment of the late 1970s and early 1980s. On the other hand, the 1983-1991 business cycle and the most recent cycles witnessed a significant upward trend in stock prices. Since the beginning of the current financial crisis, on the other hand, stock prices have declined precipitously and have been very volatile. Stock prices in 2008 and early 2009 are down significantly from 2007 levels, reflecting the financial/economic crises.

Q. What conclusions do you draw from your discussion of economic and financial conditions?

A. It is apparent that recent and current economic/financial circumstances are radically different from any that have prevailed since at least the 1930s. The recent deterioration in stock prices and the decline in U.S. Treasury bond yields and increase in corporate bond yields reflect the "flight to safety" that describes the extreme reluctance of investors to purchase common stocks and corporate bonds while moving investments into the very safe government bonds.

This "flight to safety" should not be interpreted to reflect an increase in the cost of capital, however. Rather, it more properly reflects an "availability of capital" since investors have been recently been unwilling to invest in any assets other than U.S.

Treasury bonds. As I noted previously, the opportunity cost of capital, as measured by the recent and current returns of unregulated firms, has been the lowest in recent memory. Clearly, this cannot be claimed to reflect an increase in the cost of capital for a regulated firm such as UNS Gas.

V. UNS GAS' OPERATIONS AND RISKS

Q. PLEASE SUMMARIZE UNS GAS AND ITS OPERATIONS.

A. UNS Gas is a public utility that provides natural gas distribution services to some 146,000 customers in Arizona. UNS Gas was formerly the Arizona natural gas distribution operations of Citizens Communications Company, prior to its 2003 acquisition by UniSource Energy. When UniSource Energy acquired the Arizona electric and gas assets from Citizens, it formed two operating companies - UNS Electric and UNS Gas.

Q. PLEASE DESCRIBE UNISOURCE ENERGY.

A. UniSource Energy is a holding company, whose principal subsidiary is Tucson Electric Power Company ("TEP"), a generation and distribution company that is the second-largest investor-owned utility in Arizona. UniSource Energy also owns UniSource Energy Services ("UES"), which contains UNS Electric and UNS Gas, both of which are distribution companies. It previously owned Millennium Energy Holdings, the parent company of UniSource Energy's unregulated energy business whose principal subsidiary was Global Solar. UniSource Energy presently operates through three primary business segments – TEP, UNS Electric and UNS Gas.

Q. WHAT HAVE BEEN THE BUSINESS SEGMENT RATIOS OF UNISOURCE ENERGY IN RECENT YEARS?

A. This is shown on Schedule 3. As this indicates, as of 2008, UNS Gas accounted for about 12 percent of the revenues of UniSource Energy and about 8 percent of total assets.

Q. WHAT ARE THE CURRENT BOND RATINGS OF UNISOURCE ENERGY, UNS GAS AND TEP?

A. The current ratings of UniSource Energy, UNS Gas and TEP are:

	Standard & Poor's	Moody's	Fitch
UniSource Energy Credit Ratings			
Senior Secured Debt	NR	Ba1	NR
Issuer Rating	NR	Ba1	N/A
UNS Gas Credit Ratings			
Senior Unsecured Debt		Baa3	
Tucson Electric Power Credit Ratings			
Senior Secured Debt	BBB	Baa2	BBB-
Senior Unsecured Debt	BBB-	Baa3	BB+
Issuer Rating	BB	Baa3	BB

Source: UniSource Energy Web Site.

UNS Gas now has its own security ratings by Moody's but not S&P and Fitch. The debt of UNS Gas is guaranteed by UES. As such, the debt of UNS Gas is related to the overall credit strength of UniSource Energy.

Q. **Did the acquisition of the assets current comprising UNS Gas have any impact on the security ratings of UniSource Energy or TEP?**

A. No, it did not. Standard & Poor's, for example, made the following comments in an August 12, 2003 CreditWatch report on TEP:

> Standard & Poor's Ratings Services said today it affirmed its ratings on Tucson Electric Power Co. ('BB' corporate credit rating) and removed them from CreditWatch with negative implications. They were placed on CreditWatch Nov. 8, 2002, reflecting parent UniSource Energy Corp.'s announcement of an agreement to **purchase** the **Arizona electric** and **gas transmission and distribution assets** from Citizens Communications Co. The outlook is stable.
>
> The Aug. 11, 2003, acquisition of **these relatively low-risk, widely scattered regulated assets** for $220 million, **well below the book value** of about $425 million, **bolsters the consolidated business profile** of the UniSource Energy family of companies, and does so with a financing package that **marginally improves the overall financial condition of UniSource Energy**. These assets are subject to regulation by the Arizona Corporation Commission (ACC), as is Tucson Electric, and are structured as a wholly owned subsidiary of UniSource Energy called UniSource Energy Services.

> The addition of about 77,000 electric customers and 126,000 gas customers represents an increase of about 40% to Tucson Electric's customer base. The acquisition has received strong regulatory support, mainly because rate increases will be limited to only about one-half of what they would have been in the absence of the purchase, as well as because of operational challenges faced by prior management. **[Emphasis added]**

Q. What have been the recent descriptions of UNS Gas by rating agencies?

A. In October of 2008, Moody's assigned a rating of Baa3 to UNS Gas. In its report, Moody's stated:

> Recent Developments
>
> On October 28, 2006, Moody's assigned a Baa3 rating to approximately $100 million of senior unsecured guaranteed notes (the Notes) of UNS Gas, Inc. and assigned a stable outlook. The Notes are guaranteed by UES.
>
> In July and August 2008, Moody's assigned ratings of Baa3 to UNS Gas and UNS Electric's joint $80 million guaranteed credit facility, and to UNS Electric's $100 million senior unsecured guaranteed notes. The facility and the UNS Electric notes are also guaranteed by UES.

Rating Rationale

The Baa3 rating assigned to UNS Gas' senior unsecured notes reflects the interdependence that currently exists between the company and its affiliate UNS Electric as a result of their shared credit facility and parental guarantee from UES. The rating reflects our view of the consolidated credit quality of UES, which guarantees the debt of both UNS Gas and UNS Electric. The UNS Gas/UNS Electric shared senior unsecured revolving credit facility, and the guaranteed senior unsecured notes of UNS Electric, are also rated Baa3. For additional information, please see July 8, 2008 press release and related July 9, 2008 credit opinion for UNS Gas/UNS Electric.

On a stand-alone basis, following the framework outlined in Moody's Rating Methodology for the North American Regulated Gas Distribution Industry (Local Gas Distribution Companies), (the LDC Methodology), **UNS Gas' credit profile maps to a Baa2**. The Methodology focuses on core factors including degree of profitability, the level of regulatory support, degree of ring fencing, and financial strength and flexibility as evidenced by key financial metrics and liquidity. **[Emphasis added]**

This quote by S&P indicates that the ratings of UNS Gas are:

Tied to UNS Electric;

Based on consolidated credit profile of UES; and, Lower than they would be if UNS Gas own credit profile was used to establish its ratings.

VI. CAPITAL STRUCTURE AND COST OF DEBT

Q. What is the importance of determining a proper capital structure in a regulatory framework?

A. A utility's capital structure is important because the concept of rate base – rate of return regulation requires that a utility's capital structure be determined and utilized in estimating the total cost of capital. Within this framework, it is proper to ascertain whether the utility's capital structure is appropriate relative to its level of business risk and relative to other utilities.

As discussed in Section III of my testimony, the purpose of determining the proper capital structure for a utility is to help ascertain its capital costs. The rate base – rate of return concept recognizes the assets employed in providing utility services and provides for a return on these assets by identifying the liabilities and common equity (and their cost rates) used to finance the assets. In this process, the rate base is derived from the asset side of the balance sheet and the cost of capital is derived from the liabilities/owners' equity side of the balance sheet. The inherent assumption in this procedure is that the dollar values of the capital structure and the rate base are approximately equal and the former is utilized to finance the latter.

The common equity ratio (*i.e.*, the percentage of common equity in the capital structure) is the capital structure item which normally receives the most attention. This is the case because common equity: (1) usually commands the highest cost rate; (2) generates associated income tax liabilities; and, (3) causes the most controversy since its cost cannot be precisely determined.

Q. How have you evaluated the capital structure of UNS Gas?

A. I have first examined the historic (2004-2008) capital structure ratios of UNS Gas. These are shown on Page 1 of Schedule 4. I have summarized below the common equity ratios for UNS Gas:

	Including S-T Debt	Excluding S-T Debt
2004	37.0%	37.0%
2005	44.4%	44.4%
2006	45.7%	45.7%
2007	46.9%	46.9%
2008	49.2%	49.2%

Page 2 of Schedule 4 shows the historic capital structure ratios of UniSource on a consolidated basis. This indicates the following common equity ratios:

	Including S-T Debt	Excluding S-T Debt
2004	31.6%	31.6%
2005	33.6%	33.7%
2006	34.9%	35.8%
2007	40.7%	41.0%
2008	33.9%	34.1%

These common equity ratios are somewhat lower than those of UNS Gas.

Q. How do these capital structures compare to those of investor-owned electric utilities?

A. Schedule 5 shows the common equity ratios (including short-term debt in capitalization) for the two groups of proxy utilities utilized in my cost of equity analyses. These are:

Year	Proxy Group	Grant Group
2004	41.5%	52.5%
2005	43.6%	52.4%
2006	45.1%	53.3%
2007	48.0%	54.9%
2008	47.3%	56.0%

These common equity ratios for the proxy group are lower than those of UNS Gas while those of the Grant Group are higher.

Q. What capital structure ratios has UNS Gas requested in this proceeding?

A. The Company requests use of the following capital structure:

Long-Term Debt	50.01%
Common Equity	49.99%

According to Schedule D-1 of UNS Gas' filing, this is the proforma or adjusted test year capital structure of the Company at June 30, 2008.

Q. What capital structure do you propose to use in this proceeding?

A. I use the capital structure ratios as proposed by UNS Gas.

Q. What is the cost rate of debt in the company's application?

A. The Company's filing cites a cost of long-term debt of 6.49 percent. This is represented to be the Company's actual cost at June 30, 2008. I also use this cost of long-term debt in my cost of capital analyses.

Q. Can the cost of common equity be determined with the same degree of precision as the costs of debt?

A. No. The cost rates of debt are largely determined by interest payments, issue prices, and related expenses. The cost of common equity, on the other hand, cannot be precisely quantified, primarily because this cost is an opportunity cost. There are, however, several models which can be employed to estimate the cost of common equity. Three of the primary methods – DCF, CAPM, and CE – are developed in the following sections of my testimony.

VII. SELECTION OF PROXY GROUPS

Q. How have you estimated the cost of common equity for UNS Gas?

A. UNS Gas is not a publicly-traded company. UniSource, UNS Gas' parent company, is a publicly-traded company. Consequently, it is possible to directly apply cost of equity models to UniSource. However, it is generally desirable to analyze groups of comparison or "proxy" companies as a substitute for UNS Gas to determine its cost of common equity.

I have examined two such groups for comparison to UNs Gas and UniSource. I have first selected one group of electric utilities similar to UNS Gas and UniSource using the criteria listed on Schedule 6.

Second, I have conducted studies of the cost of equity for the proxy group of natural gas utilities selected by UNS Gas' witness Kentton Grant.

VIII. DISCOUNTED CASH FLOW ANALYSIS

Q. What is the theory and methodological basis of the discounted cash flow ("DCF") model?

A. The DCF model is one of the oldest, as well as the most commonly-used, models for estimating the cost of common equity for public utilities. The DCF model is based on the "dividend discount model" of financial theory, which maintains that the value (price) of any security or commodity is the discounted present value of all future cash flows.

The most common variant of the DCF model assumes that dividends are expected to grow at a constant rate. This variant of the dividend discount model is known as the constant growth or Gordon DCF model. In this framework cost of capital is derived by the following formula:

$$K = \frac{D}{P} + g$$

where:

K = discount rate (cost of capital)

P = current price

D = current dividend rate

g = constant rate of expected growth

This formula essentially recognizes that the return expected or required by investors is comprised of two factors: the dividend yield (current income) and expected growth in dividends (future income).

Q. Please explain how you have employed the DCF model.

A. I have utilized the constant growth DCF model. In doing so, I have combined the current dividend yield for each group of proxy utility stocks described in the previous section with several indicators of expected dividend growth.

Q. How did you derive the dividend yield component of the DCF equation?

A. There are several methods that can be used for calculating the dividend yield component. These methods generally differ in the manner in which the dividend rate is employed; *i.e.*, current versus future dividends or annual versus quarterly compounding of dividends. I believe the most appropriate dividend yield component is the version listed below:

$$Yield = \frac{D_0(1+0.5g)}{P_0}$$

This dividend yield component recognizes the timing of dividend payments and dividend increases.

The P_0 in my yield calculation is the average (of high and low) stock price for each proxy company for the most recent three month period (February-April, 2009). The D_0 is the current annualized dividend rate for each proxy company.

Q. How have you estimated the dividend growth component of the DCF equation?

A. The dividend growth rate component of the DCF model is usually the most crucial and controversial element involved in using this methodology. The objective of estimating the dividend growth component is to reflect the growth expected by investors that is embodied in the price (and yield) of a company's stock. As such, it is important to recognize that individual investors have different expectations and consider alternative indicators in deriving their expectations. This is evidenced by the fact that every investment decision resulting in the purchase of a particular stock is matched by another investment decision to sell that stock. Obviously, since two investors reach different decisions at the same market price, their expectations differ.

A wide array of indicators exists for estimating the growth expectations of investors. As a result, it is evident that no single indicator of growth is always used by all investors. It therefore is necessary to consider alternative indicators of dividend growth in deriving the growth component of the DCF model.

I have considered five indicators of growth in my DCF analyses. These are:

1. 2004-2008 (5-year average) earnings retention, or fundamental growth (per Value Line);
2. 5-year average of historic growth in earnings per share ("EPS"), dividends per share ("DPS"), and book value per share ("BVPS") (per Value Line);
3. 2009, 2010, and 2012-2014 projections of earnings retention growth (per Value Line);
4. 2006-2008 to 2012-2014 projections of EPS, DPS, and BVPS (per Value Line); and
5. 5-year projections of EPS growth as reported in First Call (per Yahoo! Finance).

I believe this combination of growth indicators is a representative and appropriate set with which to begin the process of estimating investor expectations of dividend growth for the groups of proxy companies. I also believe that these growth indicators reflect the types of information that investors consider in making their investment decisions. As I indicated previously, investors have an array of information available to them, all of which should be expected to have some impact on their decision-making process.

Q. Please describe your initial DCF calculations.

A. Schedule 7 presents my DCF analysis. Page 1 shows the calculation of the "raw" (i.e., prior to adjustment for growth) dividend yield for each proxy company. Pages 2 and 3 show the growth rate for the groups of proxy companies. Page 4 shows the "raw" DCF calculations, which are presented on several bases: mean, median, and low/high values. These results can be summarized as follows:

			Mean		Median	
	Mean	Median	Low	High	Low	High
Proxy Group	10.5%	9.9%	9.0%	11.9%	9.8%	11.9%
Grant Group	9.6%	9.5%	8.8%	10.3%	8.3%	9.5%

I note that the individual DCF calculations shown on Schedule 7 should not be interpreted to reflect the expected cost of capital for the proxy group; rather, the individual values shown should be interpreted as alternative information considered by investors. The individual DCF calculations also demonstrate how the focus on a single growth rate, such as EPS projections, can produce a DCF conclusion that is not reflective of a broader perspective of available information.

The results in Schedule 7 indicate average (mean and median) DCF cost rates of 9.5 percent to 10.5 percent. The range of DCF rates (i.e., using the lowest and highest growth rates only) are 8.8 percent 11.9 percent.

Q. What do you conclude from your DCF analysis?

A. This analysis reflects a DCF range of about 9.5 percent to about 10.5 percent for the proxy group. This is approximated by the average/mean values for the proxy groups examined in the previous analysis. I give less weight to the extreme lower and upper ends of the groups, which are impacted by outlier results. I believe that 9.5 percent to 10.5 percent reflects the proper DCF cost for UNS Gas.

IX. CAPITAL ASSET PRICING MODEL ANALYSIS

Q. Please describe the theory and methodological basis of the capital asset pricing model ("CAPM").

A. The CAPM is a version of the risk premium method. The CAPM describes and measures the relationship between a security's investment risk and its market rate of return. The CAPM was developed in the 1960s and 1970s as an extension of modern portfolio theory ("MPT"), which studies the relationships among risk, diversification, and expected returns.

Q. How is the CAPM derived?

A. The general form of the CAPM is:

$$K = R_f + \beta(R_m - R_f)$$

where:

K = cost of equity

Rf = risk free rate

Rm = return on market

β = beta

Rm-Rf = market risk premium

As noted previously, the CAPM is a variant of the risk premium method. I believe the CAPM is generally superior to the simple risk premium method because the CAPM specifically recognizes the risk of a particular company or industry (*i.e.*, beta), whereas the simple risk premium method assumes the same risk premium for all companies exhibiting similar bond ratings.

Q. What groups of companies have you utilized to perform your CAPM analyses?

A. I have performed CAPM analyses for the same groups of proxy utilities evaluated in my DCF analyses.

Q. Please explain the risk-free rate as used in your CAPM and indicate what rate you employed.

A. The first term of the CAPM is the risk-free rate (R_f). The risk-free rate reflects the level of return that can be achieved without accepting any risk.

In CAPM applications, the risk-free rate is generally recognized by use of U.S. Treasury securities. Two general types of U.S. Treasury securities are often utilized as the R_f component - short-term U.S. Treasury bills and long-term U.S. Treasury bonds.

I have performed CAPM calculations using the three-month average yield (February-April, 2009) for 20-year U.S. Treasury bonds. Over this three-month period, these bonds had an average yield of 3.82 percent.

Q. What is beta and what betas did you employ in your CAPM?

A. Beta is a measure of the relative volatility (and thus risk) of a particular stock in relation to the overall market. Betas of less than 1.0 are considered less risky than the market, whereas betas greater than 1.0 are more risky. Utility stocks traditionally have had betas below 1.0. I utilized the most recent Value Line betas for each company in the groups of proxy utilities.

Q. How did you estimate the market risk premium component in your CAPM analysis?

A. The market risk premium component (R_m-R_f) represents the investor-expected premium of common stocks over the risk-free rate, or government bonds. For the purpose of estimating the market risk premium, I considered alternative measures of returns of the S&P 500 (a broad-based group of large U.S. companies) and 20-year U.S. Treasury bonds.

First, I have compared the actual annual returns on equity of the S&P 500 with the actual annual yields of U.S. Treasury bonds. Schedule 8 shows the return on equity for the S&P 500 group for the period 1978-2007 (all available years reported by S&P). This schedule also indicates the annual yields on 20-year U.S. Treasury bonds, as well as the annual differentials (*i.e.*, risk premiums) between the S&P 500 and U.S. Treasury 20-year bonds. Based upon these returns, I conclude that this version of the risk premium is about 6.45 percent.

I have also considered the total returns (i.e., dividends/interest plus capital gains/losses) for the S&P 500 group as well as for the long-term government bonds, as tabulated by Morningstar (formerly Ibbotson Associates), using both arithmetic and geometric means. I have considered the total returns for the entire 1926-2008 period, which are as follows:

	S&P 500	L-T Gov't Bonds	Risk Premium
Arithmetic	11.7%	6.1%	5.6%
Geometric	9.6%	5.7%	3.9%

I conclude from this that the expected risk premium is about 5.32 percent (i.e., average of all three risk premiums). I believe that a combination of arithmetic and geometric means is appropriate since investors have access to both types of means and, presumably, both types are reflected in investment decisions and thus stock prices and cost of capital.

Schedule 9 shows my CAPM calculations using the risk premium. The results are:

	Mean	Median
Proxy Group	7.7%	7.5%
Grant Group	7.4%	7.3%

Q. What is your conclusion concerning the CAPM cost of equity?

A. The CAPM results collectively indicate a cost of 7.3 percent to 7.7 percent for the groups of comparison utilities. I conclude that the CAPM cost of equity for UNS Gas is 7.3 percent to 7.5 percent.

X. COMPARABLE EARNINGS ANALYSIS

Q. Please describe the basis of the CE methodology.

A. The CE method is derived from the "corresponding risk" standard of the Bluefield and Hope cases. This method is thus based upon the economic concept of opportunity cost. As previously noted, the cost of capital is an opportunity cost: the prospective return available to investors from alternative investments of similar risk.

The CE method is designed to measure the returns expected to be earned on the original cost book value of similar risk enterprises. Thus, this method provides a direct measure of the fair return, because the CE method translates into practice the competitive principle upon which regulation is based.

The CE method normally examines the experienced and/or projected returns on book common equity. The logic for examining returns on book equity follows from the use of original cost rate base regulation for public utilities, which uses a utility's book common equity to determine the cost of capital. This cost of capital is, in turn, used as the fair rate of return which is then applied (multiplied) to the book value of rate base to establish the dollar level of capital costs to be recovered by the utility. This technique is thus consistent with the rate base methodology used to set utility rates.

Q. How have you employed the CE methodology in your analysis of UNS Gas' common equity cost?

A. I conducted the CE methodology by examining realized returns on equity for several groups of companies and evaluating the investor acceptance of these returns by reference to the resulting market-to-book ratios. In this manner it is possible to assess the degree to which a given level of return equates to the cost of capital. It is generally recognized for utilities that market-to-book ratios of greater than one (*i.e.,* 100%) reflect a situation where a company is able to attract new equity capital without dilution (*i.e.*, above book value). As a result, one objective of a fair cost of equity is the maintenance of stock prices above book value.

I would further note that the CE analysis, as I have employed it, is based upon market data (through the use of market-to-book ratios) and is thus essentially a market test. As a result, my analysis is not subject to the criticisms occasionally made by some who maintain that past earned returns do not represent the cost of capital. In addition, my analysis uses prospective returns and thus is not confined to historical data.

Q. What time periods have you examined in your CE analysis?

A. My CE analysis considers the experienced equity returns of the proxy groups of utilities for the period 1992-2008 (*i.e.,* the last seventeen years). The CE analysis requires that I examine a relatively long period of time in order to determine trends in earnings over at least a full business cycle. Further, in estimating a fair level of return for a future period, it is important to examine earnings over a diverse period of time in order to avoid any undue influence from unusual or abnormal conditions that may occur in a single year or shorter period. Therefore, in forming my judgment of the current cost of equity I have focused on two periods: 2002-2008 (the current business cycle) and 1992-2001 (the most recent complete business cycle).

Q. PLEASE DESCRIBE YOUR CE ANALYSIS.

A. Schedules 10 and 11 contain summaries of experienced returns on equity for several groups of companies, while Schedule 12 presents a risk comparison of utilities versus unregulated firms.

Schedule 10 shows the earned returns on average common equity and market-to-book ratios for the groups of proxy utilities. These can be summarized as follows:

	Proxy Group	Grant Group
Historic ROE		
Mean	8.3-10.0%	11.8-11.9%
Median	8.3-11.1%	11.9-12.1%
Historic M/B		
Mean	133-152%	179-183%
Median	124-144%	180-183%
Prospective ROE		
Mean	8.4-9.2%	11.4-11.7%
Median	8.6-8.5%	11.0-12.3%

These results indicate that historic returns of 8.3 percent to 12.1 percent have been adequate to produce market-to-book ratios of 124 percent to 183 percent for the groups of proxy utilities, with the higher returns being accompanied by the higher market-to-book ratios. Furthermore, projected returns on equity for 2009, 2010, and 2012-2014 are within a range of 8.0 percent to 12.3 percent for the utility groups. These relate to 2008 market-to-book ratios of 127 percent or higher again with the higher returns accompanying the higher market-to-book ratios.

Q. Have you also reviewed earnings of unregulated firms?

A. Yes. As an alternative, I also examined a group of largely unregulated firms. I have examined the Standard & Poor's 500 Composite group, since this is a well-recognized group of firms that is widely utilized in the investment community and is indicative of the competitive sector of the economy. Schedule 11 presents the earned returns on equity and market-to-book ratios for the S&P 500 group over the past sixteen years. As this Schedule indicates, over the two periods this group's average earned returns ranged from 13.9 percent to 14.7 percent with market-to-book ratios ranging between 284 percent and 341 percent.

Q. How can the above information be used to estimate the cost of equity for UNS Gas?

A. The recent earnings of the proxy utility and S&P 500 groups can be utilized as an indication of the level of return realized and expected in the regulated and competitive sectors of the economy. In order to apply these returns to the cost of equity for proxy utilities, however, it is necessary to compare the risk levels of the utility industry with those of the competitive sector. I have done this in Schedule 12, which compares several risk indicators for the S&P 500 group and the utility groups. The information in this schedule indicates that the S&P 500 group is more risky than the utility proxy groups.

Q. What return on equity is indicated by the CE analysis?

A. Based on the recent earnings and market-to-book ratios, I believe the CE analysis indicates that the cost of equity for the proxy utilities is no more than 9.5 percent to 10.5 percent. Recent returns of 8.3 percent to 12.1 percent have resulted in market-to-book ratios of 124 and greater. Prospective returns of 8.0 percent to 12.3 percent result in anticipated market-to-book ratios of over 125 percent, again with the higher returns being associated with much higher market-to-book ratios. As a result, it is apparent that returns below this level would result in market-to-book ratios of well above 100 percent. An earned return of 9.5 percent to 10.5 percent should thus result in a market-to-book ratio of over 100 percent. As I indicated earlier, the fact that market-to-book ratios substantially exceed 100 percent indicates that historic and prospective returns of over 10 percent reflect earnings levels that exceed the cost of equity for those regulated companies.

Please also note that my CE analysis is not based on a mathematic formula approach, as are the DCF and CAPM methodologies. Rather, it is based on recent trends and current conditions in equity markets. Further, it is based on the direct relationship between returns on common stock and market-to-book ratios of common stock. In utility rate setting, a fair rate of return is based on the utility's assets (*i.e.*, rate base) and the book value of the utility's capital structure. As stated earlier, maintenance of a financially stable utility's market-to-book ratio at 100 percent, or a bit higher, is fully adequate to maintain the utility's financial stability. On the other hand, a market price of a utility's common stock that is 150 percent or more above the stock's book value is indicative of earnings that exceed the utility's reasonable cost of capital. Thus, actual or projected earnings do not directly translate into a utility's reasonable cost of equity. Rather, they must be viewed in relation to the market-to-book ratios of the utility's common stock.

My 9.5 percent to 10.5 percent CE recommendation is not designed to result in market-to-book ratios as low as 1.0 for UNS Gas. Rather, it is based on current market conditions and the proposition that ratepayers should not be required to pay rates based on earnings levels that result in excessive market-to-book ratios.

XI. RETURN ON EQUITY RECOMMENDATION

Q. Please summarize the results of your three cost of equity analyses.

A. My three methodologies produce the following:

Discounted Cash Flow	9.5-10.5%
Capital Asset Pricing Model	7.3-7.7%
Comparable Earnings	9.5-10.5%

Q. What is your cost of equity recommendation for UNS Gas?

A. I recommend a cost of equity of 9.5 percent to 10.5 percent for UNS Gas. This reflects two of my three cost of equity model results. Within this range, I recommend a 10.0 percent level, the same return on equity approved for UNS Gas in the Company's last rate proceeding.

Q. Please explain how the recent and current economic and financial crisis impacts the cost of equity for UNS Gas.

A. It is well chronicled that, over the past two years and especially over the past several months, the United States and global financial markets have been in turmoil. The impacts of this have been far-reaching and extreme, with global credit markets virtually coming to a standstill. This crisis and its impact, however, do not imply that the cost of equity for gas utilities such as UNS Gas have increased. I say this for the following reasons.

First, it must be emphasized that depressed economic conditions and the financial crisis affects virtually all sectors of the economy – households, small businesses, larger commercial and industrials – and, in most cases, the impact is greater than is the case for UNS Gas. UNS Gas is a regulated utility that sells a product that has no real substitutes and is a product that consumers can do little to control the amount they use. As such, UNS Gas and utilities are partially, if not largely, insulated from the impacts of depressed economic conditions.

Second, the major impact of a recession will be to depress the profits of most enterprises. As a result, it is to be expected that capital costs will decrease in tandem with a significant recession. There is no justification for increasing the profit level of a regulated utility such as UNS Gas at the same time that other enterprises are experiencing lower profits.

Third, even if UNS Gas were to incur higher costs of debt and/or other capital costs, these costs can be passed along to ratepayers at the next rate proceeding. Unregulated firms cannot do this.

Fourth, there is no indication that UNS Gas' risks have increased since its last rate proceeding. Absent a demonstration that UNS Gas' risks have increased, there is no justification for increasing its cost of equity.

Fifth, the United States and global governments have and are taking extraordinary measures to avoid a further worsening of the current market turmoil. Most of these measures are designed to put liquidity into the credit markets and make credit more accessible again and, in the process, restore more confidence to the financial markets. All of these measures are clearly designed to lower the cost of capital. In this environment, it would be counter-productive to make any claim that UNS Gas should have a higher return at this time due to the above-cited market turmoil.

XII. TOTAL COST OF CAPITAL

Q. What is the total cost of capital for UNS Gas?

A. Schedule 1 reflects the total cost of capital for the Company using UNS Gas' proposed capital structure and cost of debt along with the range of common equity costs my analyses support. The resulting total cost of capital is a range of 7.99 percent to 8.49 percent. I recommend that a 8.24 percent total cost of capital be established for UNS Gas.

Q. Does your cost of capital recommendation provide the company with a sufficient level of earnings to maintain its financial integrity?

A. Yes, it does. Schedule 14 shows the pre-tax coverage that would result if UNS Gas earned my cost of capital recommendation. As the results indicate, my recommended range would produce a coverage level above the benchmark range for a BBB rated utility. In addition, the debt ratio (which reflects the Company's proposed capital structure) is within the benchmark for a BBB rated utility.

XIII. COMMENTS ON COMPANY TESTIMONY

Q. Have you reviewed the testimony and cost of capital recommendation of UNS Gas witness Kentton C. Grant?

A. Yes, I have. Mr. Grant is recommending the following cost of capital for UNS Gas.

Capital Item	Percent	Cost	Weighted Cost
Long-term Debt	50.01%	6.49%	3.25%
Common Equity	49.99%	11.00%	5.50%
Total	100.0%		8.75%

Mr. Grant's 11.0 percent cost of common equity recommendation is derived as follows:

	Range	Average
DCF	9.5-11.2%%	10.1%
CAPM	10.2-11.3%	10.7%
Risk Premium	10.2-11.5%	

Q. Do you have any comments concerning Mr. Grant's DCF analysis and recommendations?

A. I note that Mr. Grant's 10.1 percent DCF conclusion is based upon his application of a DCF model to a group of 10 gas distribution utilities. This 10.1 percent average is nearly identical to my 10.0 percent DCF mid-point.

Q. What are you comments concerning Mr. Grant's CAPM analysis and conclusions?

A. Mr. Grant's CAPM analysis takes the following form:

Risk-free rate =	4.53%	=	August 2007 20-yr. T bonds Yield
Risk Premium =	7.1%	=	MorningStar risk premium
Beta =		=	Value Line

My primary disagreement is with Mr. Grant's risk premium input. My disagreements with Mr. Grant's risk premium are his exclusive reliance on the 1926-2007 arithmetic average differences between large company stocks (i.e., S&P 500) and long-term Treasury bonds. As I indicated earlier in my testimony, it is preferable to use multiple sources of risk premium measures, as I have done. Mr. Grant's 7.1 percent risk premium used only arithmetic returns, and ignores geometric (compound) returns in deriving the risk premium component of the CAPM. This is not proper. It is apparent that investors have access to both types of returns, and correspondingly use both types of returns, which they make investment decisions.

In fact, it is noteworthy that mutual fund investors regularly receive reports on their own funds, as well as prospective funds they are considering investing in, that show only geometric returns. Based on this, I find it difficult to accept Mr. Grant's position that only arithmetic returns are considered by investors, and, thus, only arithmetic returns are appropriate in a CAPM context.

I also disagree with Mr. Grant's 7.1 percent risk premium since it improperly used "income returns" from the Morningstar study rather than "total returns." What Mr. Grant did was compare the differential between total returns for common stocks (i.e., dividends and capital gains) and only income returns for Treasury bonds. As such, he has ignored the capital gains component of the Treasury bonds return. As I indicated in my earlier testimony, the differential between total returns of common stocks and Treasury bonds, is 5.6 percent on an arithmetic basis. In addition, Mr. Grant's use of the Morningstar study only used half of the reported data (arithmetic means) and ignored the other half of the reported data (geometric means).

It is apparent that, when Mr. Grant's historic risk premium estimate is updated for the inclusion of 2008 data, a much different picture emerges. The 1926-2008 differential between the arithmetic returns of the S&P 500 and long-term government bonds has declined from 6.5 percent to 5.6 percent (i.e., 11.7 percent total return for S&P 500 minus 6.1 percent total return for long-term government bonds), a reduction of 90 basis points. A similar update of his "income return" would have the effect of reducing his CAPM risk premium to 6.5 percent, or 60 basis points.

Q. What are your comments about Mr. Grant's equity risk premium method and results?

A. Mr. Grant's equity risk premium method looks at the relationship between state regulatory commission return on equity awards and corresponding public utility bond yields over the period 2003 – mid 2008. On page 23 and KCG-11, he concludes that a range of 3.75 percent to 5.0 percent reflects the appropriate spread between the cost of equity and utility bond yields, reflecting the average value of the spread (i.e., 4.375 percent) plus or minus one standard deviation. I do not believe that the upper portion of Mr. Grant's 3.75 percent to 5.5 percent equity risk premium range is appropriate. Consider, for example, the average awarded returns on equity and triple-B bond yields over the past few years:

Year	Auth. ROE	Baa Yields	Spread
2005	10.54%	5.93%	4.61%
2006	10.36%	6.32%	4.04%
2007	10.36%	6.33%	4.03%
2008	10.46%	7.25%	3.21%
Average			3.97%

This indicates an average equity risk premium of about 4 percent over this period. Combining this 4 percent equity risk premium with Mr. Grant's estimate of 6.48 percent for public utility bonds in August results in a cost of equity of about 10.5 percent, the top end of my recommended range.

Q. Mr. Grant also makes an adjustment for the size of UNS Gas, is this proper?

A. No, it is not. UNS Gas does not raise its own equity capital (as it comes from UniSource Energy) and its debt is guaranteed by UES. As a result, it is these entities that are evaluated by investors and it is the size of these entities that investors consider.

XIV. FAIR VALUE RATE BASE ("FVRB") COST OF CAPITAL

Q. What is your understanding of UNS Gas's position on the issue of fair value rate base and related cost of capital implications?

A. It is my understanding that UNS Gas is requesting that a 6.80 percent cost of capital be applied to the level of its FVRB.

Q. What is your understanding of the commission's procedure for utilizing the fair value of rate base in setting utility rates?

A. My "non-legal understanding" is that the Commission must consider the fair value of a utility's assets in setting rates. However, I do not agree that this implies that the Company's cost of capital must be applied to the fair value of the rate base.

Q. Are you aware that the Commission has recently conducted a "remand" hearing on the issue of regulatory treatment of FVRB for Chaparral City Water Company?

A. Yes, I am. In January of 2008, the Commission conducted a public hearing in response to a remand by the Arizona Court of Appeals (No. CA-CC 05-002)[2] in Chaparral City Water Company (Docket No. W-02113A-04-0616). The purpose of this hearing was to determine the appropriate cost of capital to be applied to an Arizona utility's fair value rate base. The Commission's Decision No. 70441 in this proceeding established a Fair Value Rate of Return ("FVROR") by subtracting the inflation rate from the cost of equity.

Q. What is your understanding of the use of FVRB in Arizona?

A. My "non-legal understanding" is based in part on the 2006 Arizona Court of Appeals in the Chaparral City case that indicates that the Court agreed with the Commission that "the cost of capital analysis 'is geared to concepts of original cost measures of rate base, not fair value measures of rate base . . . ." The decision goes on to make the following statement: "If the Commission determines that the cost of capital analysis is not the appropriate methodology to determine the rate of return to be applied to the FVRB, the Commission has the discretion to determine the appropriate methodology." It is correspondingly the purpose of this section of my testimony to recommend an "appropriate methodology" for use in conjunction with a FVRB.

[2] CA-CC 05-0002, Memorandum Decision dated February 13, 2007.

Q. Do you have any observations based upon your own experience in cost of capital determination, as to whether a cost of capital developed for application to an original cost rate base is consistent with a FVRB?

A. Yes, I do. It is my personal experience, based upon over 35 years of providing cost of capital testimony, that the concept of cost of capital is designed to apply to an original cost rate base. This is the case since the cost of capital is derived from the liabilities/owners' equity side of a utility's balance sheet using the book values of the capital structure components. The cost of capital, once determined, is then applied to (i.e., multiplied by) the rate base, which is derived from the asset side of the balance sheet (i.e., OCRB). From a financial perspective, the rationale for this relationship is that the rate base is financed by the capitalization. Under this relationship, a provision is provided for investors (both lenders and owners) to receive a return on their invested capital. Such a relationship is meaningful as long as the cost of capital is applied to the original cost (i.e., book value) rate base, because there is a matching of rate base and capitalization.

When the concept of fair value rate base is incorporated, however, this link between rate base and capital structure is broken. The amount of fair value rate base that exceeds original cost rate base is not financed with investor-supplied funds and, indeed, is not financed at all. As a result, a customary cost of capital analysis cannot be automatically applied to the fair value rate base since there is no financial link between the two concepts. In my "non-legal" opinion, both the Commission and Appeals Court have also recognized this lack of compatibility between a customary weighted cost of capital ("WCOC") analysis and FVRB.

Q. Why is it important that there be a link between the concepts of rate base and cost of capital?

A. This link is important since financial theory indicates that investors should be provided an opportunity to earn a return on the capital they provided to the utility. Since the capital finances the rate base (in an original cost world), the link between cost of capital and rate base satisfies this financial objective.

Q. Based on your experience as a cost of capital witness over the past 35 years, do you have a suggestion as to how to account for the use of a FVRB in setting rates for UNS Gas?

A. Yes, I do. Since the increment between fair value rate base and original cost rate base is not financed with investor-supplied funds, it is logical and appropriate, from a financial standpoint, to assume that this increment has no financing cost. As a result, the cost of capital, through the capital structure, can be modified to account for a level of cost-free capital in an equal dollar amount to the increment of FVRB over the OCRB. Such a procedure would still provide for a return being earned on all investor-supplied funds and would thus be consistent with financial standards.

Q. Have you made such a proposal in this proceeding?

A. Yes, I have. As is shown below, I have developed a capital structure and FVROR that applies to UNS Gas' FVRB.

Item	Amount (000)	Percent	Cost	Fair Value Return
Long-term Debt	$99,265	36.56%	6.49%	2.37%
Common Equity	99,242	36.55%	10.00%	3.66%
FVRB Increment[3]	73,015	26.89%	0.00%	0.00%
Total FVRB Capital	$271,522	100.00%		6.03%

Applying this 6.03 percent to the FVRB provides for a return on all investor-supplied capital and is therefore an appropriate rate to apply to the FVRB from a financial and economic standpoint. As such, it provides for an appropriate fair value rate of return to be applied to a FVRB.

Q. **Have you developed an alternative method with which to apply a FVROR to a FVRB?**

A. Yes, I have. Should the Commission determine that there should be a specific return (greater than zero) applied to the FVRB Increment, I have provided such a procedure.

Q. **Why is it necessary to add a return on only the portion of FVRB that exceeds the OCRB?**

A. The WCOC authorized by the Commission has already provided for a full cost of equity return and cost of debt on the portions of equity and debt capital that are supporting the

[3] FVRB minus OCRB.

OCRB portion of the FVRB. As a result, there is no need to provide any additional return on the portions of FVRB supported by common equity and debt.

Stated differently, both the cost of debt and the return on common equity (i.e., capital stock, paid-in capital, and retained earnings - the investment of common shareholders) are already provided for in a traditional WCOC. Only the portion of the FVRB that exceeds OCRB ("Fair Value Increment") needs to have a specific return identified in order to reflect a return component on that Fair Value Increment.

Q. What is the proper cost rate to apply to the fair value increment?

A. As I indicated previously, from a financial perspective, it should not be necessary to provide for <u>any</u> return on the Fair Value Increment since this is not investor-supplied capital. However, the Commission may choose to evaluate this issue from both a financial and a public policy perspective. I am aware that UNS Gas may claim that the concept of fair value carries with it the notion that investors should receive some benefit when fair value is greater than original cost and should suffer some detriment when fair value is less than original cost. It is possible that the Commission may determine that Arizona's fair value provision, which is somewhat unique, is not inconsistent with these concepts. Nonetheless, the idea that the Company should receive some benefit from the Fair Value Increment does not mean that one should automatically apply to the FVRB a WCOC developed by reference to original cost rate base. If it is determined that it is desirable to provide an additional (non-zero) return on the Fair Value Increment, the proper return should be no larger than the real (i.e., after inflation is removed) risk-free rate of return.

Q. What is the risk-free return?

A. The risk-free return is, in financial terms, the return on an investment that carries little or no risk. Risk-free investments are universally defined as U.S. Treasury Securities, with short-term maturities usually being used as the risk-free rate. Over the past several months, various maturities of U.S. Treasury securities have yielded from about 0.05 percent (short-term) to 4.0 percent (long-term) in nominal terms. I also note that 2009-2010 forecasts of U.S. Treasury securities are about 1.0 percent to 4.5 percent. As a result, I use 4.5 percent as the nominal risk-free rate.

Q. What is the "real" risk-free rate?

A. The concept of real rates involves the removal of the rate of inflation from the nominal risk-free rate. In 2008, the rate of inflation, as measured by the Consumer Price Index ("CPI"), was 0.1 percent. Forecasts of the CPI for 2009-2010 are about 1.5 percent to 2.2 percent. As a result, I propose to use a 2.0 percent inflation rate for computing the real risk-free rate, which is computed as follows:

Nominal Risk-Free Rate	4.5%
Less: Inflation Rate	2.0%
Equals: Real Risk-Free Rate	2.5%

Q. Please explain why UNS Gas' FVROR should consider the real risk-free rate, as opposed to the nominal risk-free rate.

A. The investors of UNS Gas are already receiving an inflation factor due to the inclusion of inflation in the FVRB Increment. Specifically, the Fair Value Increment incorporates inflation by considering the current value of assets, which reflect, in part, past inflation.

It would be double-counting to also include the inflation components in the return to be applied to the FVRB Increment.

Q. What return on the Fair Value Increment do you recommend in your alternative FVROR proposal?

A. My alternative FVROR proposal incorporates a return on the Fair Value Increment with a maximum value of 2.5 percent, as developed above. However, I wish to emphasize that this 2.5 percent value is the maximum value that could be applied to the FVRB Increment. In reality, any value between zero percent and 2.5 percent could be used as the cost rate on the FVRB Increment. As I stated above, this Fair Value Increment return is in addition to the return that the Company's investors already earn on their investment in the Company. In this sense, an above-zero cost rate for the fair value increment represents a bonus to the Company that would have to find its justification in policy considerations instead of in pure economic or financial principles; for that reason, the selection of an appropriate cost rate within this range should fall to the Commission's discretion. I would propose the mid-point of this range, or 1.25 percent.

Q. What is the resulting impact of your alternative proposal in this proceeding?

A. I am proposing the following modified FVROR for UNS Gas:

Capital Item	Percent	Cost	Return
Long-term Debt	36.56%	6.49%	2.37%
Common Equity	36.55%	10.00%	3.66%
FVRB Increment	26.89%	1.25%	0.34%
Total	100.00%		6.37%

As shown in the above table, this alternative proposal provides for a non-zero return on the Fair Value Increment of UNS Gas, and provides for an overall fair value rate of return of 6.37 percent on the FVRB.

Q. Does this conclude your direct testimony?

A. Yes, it does.

BACKGROUND AND EXPERIENCE PROFILE
DAVID C. PARCELL, MBA, CRRA
PRESIDENT/SENIOR ECONOMIST

EDUCATION

1985	M.B.A., Virginia Commonwealth University
1970	M.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)
1969	B.A., Economics, Virginia Polytechnic Institute and State University, (Virginia Tech)

POSITIONS

2007-Present	President, Technical Associates, Inc.
1995-2007	Executive Vice President and Senior Economist, Technical Associates, Inc.
1993-1995	Vice President and Senior Economist, C. W. Amos of Virginia
1972-1993	Vice President and Senior Economist, Technical Associates, Inc.
1969-1972	Research Economist, Technical Associates, Inc.
1968-1969	Research Associate, Department of Economics, Virginia Polytechnic Institute and State University

ACADEMIC HONORS

Omicron Delta Epsilon - Honor Society in Economics
Beta Gamma Sigma - National Scholastic Honor Society of Business Administration
Alpha Iota Delta - National Decision Sciences Honorary Society
Phi Kappa Phi - Scholastic Honor Society

PROFESSIONAL DESIGNATIONS

Certified Rate of Return Analyst - Founding Member
Member of Association for Investment Management and Research (AIMR)

RELEVANT EXPERIENCE

Financial Economics -- Advised and assisted many Virginia banks and savings and loan associations on organizational and regulatory matters. Testified approximately 25 times before the Virginia State Corporation Commission and the Regional Administrator of National Banks on matters related to branching and organization for banks, savings and loan associations, and consumer finance companies. Advised financial institutions on interest rate structure and loan maturity. Testified before Virginia State Corporation Commission on maximum rates for consumer finance companies.

Testified before several committees and subcommittees of Virginia General Assembly on numerous banking matters.

Clients have included First National Bank of Rocky Mount, Patrick Henry National Bank, Peoples Bank of Danville, Blue Ridge Bank, Bank of Essex, and Signet Bank.

Published articles in law reviews and other periodicals on structure and regulation of banking/financial services industry.

Utility Economics -- Performed numerous financial studies of regulated public utilities. Testified in over 300 cases before some thirty state and federal regulatory agencies.

Prepared numerous rate of return studies incorporating cost of equity determination based on DCF, CAPM, comparable earnings and other models. Developed procedures for identifying differential risk characteristics by nuclear construction and other factors.

Conducted studies with respect to cost of service and indexing for determining utility rates, the development of annual review procedures for regulatory control of utilities, fuel and power plant cost recovery adjustment clauses, power supply agreements among affiliates, utility franchise fees, and use of short-term debt in capital structure.

Presented expert testimony before federal regulatory agencies Federal Energy Regulatory Commission, Federal Power Commission, and National Energy Board (Canada), state regulatory agencies in Alabama, Alaska, Arizona, Arkansas, California, Connecticut, Delaware, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maine, Maryland, Missouri, Nebraska, Nevada, New Hampshire, New Jersey, New Mexico, Ohio, Oklahoma, Ontario (Canada), Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, West Virginia, Washington, Wisconsin, and Yukon Territory (Canada).

Published articles in law reviews and other periodicals on the theory and purpose of regulation and other regulatory subjects.

Clients served include state regulatory agencies in Alaska, Arizona, Delaware, Missouri, North Carolina, Ontario (Canada), and Virginia; consumer advocates and attorneys general in Alabama, Arizona, District of Columbia, Florida, Georgia, Hawaii, Illinois, Indiana, Kansas, Kentucky, Maryland, Nevada, New Mexico, Ohio, Oklahoma, Pennsylvania, South Carolina, Texas, Utah, Vermont, Virginia, and West Virginia; federal agencies including Defense Communications Agency, the Department of Energy, Department of the Navy, and General Services Administration; and various organizations such as Bath Iron Works, Illinois Citizens' Utility Board, Illinois Governor's Office of Consumer Services, Illinois Small Business Utility Advocate, Wisconsin's Environmental Decade, Wisconsin's Citizens Utility Board, and Old Dominion Electric Cooperative.

Insurance Economics -- Conducted analyses of the relationship between the investment income earned by insurance companies on their portfolios and the premiums charged for insurance. Analyzed impact of diversification on financial strength of Blue Cross/Blue Shield Plans in Virginia.

Conducted studies of profitability and cost of capital for property/casualty insurance industry. Evaluated risk of and required return on surplus for various lines of insurance business.

Presented expert testimony before Virginia State Corporation Commission concerning cost of capital and expected gains from investment portfolio. Testified before insurance bureaus of Maine, New Jersey, North Carolina, Rhode Island, South Carolina and Vermont concerning cost of equity for insurance companies.

Prepared cost of capital and investment income return analyses for numerous insurance companies concerning several lines of insurance business. Analyses used by Virginia Bureau of Insurance for purposes of setting rates.

Special Studies -- Conducted analyses which evaluated the financial and economic implications of legislative and administrative changes. Subject matter of analyses include returnable bottles, retail beer sales, wine sales regulations, taxi-cab taxation, and bank regulation. Testified before several Virginia General Assembly subcommittees.

Testified before Virginia ABC Commission concerning economic impact of mixed beverage license.
Clients include Virginia Beer Wholesalers, Wine Institute, Virginia Retail Merchants Association, and Virginia Taxicab Association.
Franchise, Merger & Anti-Trust Economics -- Conducted studies on competitive impact on market structures due to joint ventures, mergers, franchising and other business restructuring. Analyzed the costs and benefits to parties involved in mergers. Testified in federal courts and before banking and other regulatory bodies concerning the structure and performance of markets, as well as on the impact of restrictive practices.

Clients served include Dominion Bankshares, asphalt contractors, and law firms.

Transportation Economics -- Conducted cost of capital studies to assess profitability of oil pipelines, trucks, taxicabs and railroads. Analyses have been presented before the Federal Energy Regulatory Commission and Alaska Pipeline Commission in rate proceedings. Served as a consultant to the Rail Services Planning Office on the reorganization of rail services in the U.S.
Economic Loss Analyses -- Testified in federal courts, state courts, and other adjudicative forums regarding the economic loss sustained through personal and business injury whether due to bodily harm, discrimination, non-performance, or anticompetitive practices. Testified on economic loss to a commercial bank resulting from publication of adverse information concerning solvency. Testimony has been presented on behalf of private individuals and business firms.

MEMBERSHIPS

American Economic Association
Virginia Association of Economists
Richmond Society of Financial Analysts
Financial Analysts Federation
Society of Utility and Regulatory Financial Analysts

Board of Directors	1992-2000
Secretary/Treasurer	1994-1998
President	1998-2000

RESEARCH ACTIVITY

Books and Major Research Reports

"Stock Price As An Indicator of Performance," Master of Arts Thesis, Virginia Tech, 1970

"Revision of the Property and Casualty Insurance Ratemaking Process Under Prior Approval in the Commonwealth of Virginia," prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Charles Schotta and Michael J. Ileo, 1971

"An analysis of the Virginia Consumer Finance Industry to Determine the Need for Restructuring the Rate and Size Ceilings on Small Loans in Virginia and the Process by which They are Governed," prepared for the Virginia Consumer Finance Association, with Michael J. Ileo, 1973

State Banks and the State Corporation Commission: A Historical Review, Technical Associates, Inc., 1974

"A Study of the Implications of the Sale of Wine by the Virginia Department of Alcoholic Beverage Control", prepared for the Virginia Wine Wholesalers Association, Virginia Retail Merchants Association, Virginia Food Dealers Association, Virginia Association of Chain Drugstores, Southland Corporation, and the Wine Institute, 1983.

"Performance and Diversification of the Blue Cross/Blue Shield Plans in Virginia: An Operational Review", prepared for the Bureau of Insurance of the Virginia State Corporation Commission, with Michael J. Ileo and Alexander F. Skirpan, 1988.
The Cost of Capital - A Practitioners' Guide, Society of Utility and Regulatory Financial Analysts, 1997 (previous editions in 1991, 1992, 1993, 1994, and 1995).

Papers Presented and Articles Published

"The Differential Effect of Bank Structure on the Transmission of Open Market Operations," Western Economic Association Meeting, with Charles Schotta, 1971

"The Economic Objectives of Regulation: The Trend in Virginia," (with Michael J. Ileo), William and Mary Law Review, Vol. 14, No. 2, 1973

"Evolution of the Virginia Banking Structure, 1962-1974: The Effects of the Buck-Holland Bill", (with Michael J. Ileo), William and Mary Law Review, Vol. 16, No. 3, 1975

"Banking Structure and Statewide Branching: The Potential for Virginia", William and Mary Law Review, Vol. 18, No. 1, 1976

"Bank Expansion and Electronic Banking: Virginia Banking Structure Changes Past, Present, and Future," William and Mary Business Review," Vol. 1, No. 2, 1976

"Electronic Banking - Wave of the Future?" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 1, 1976

"The Pricing of Electricity" (with James R. Marchand), Journal of Management and Business Consulting, Vol. 1, No. 2, 1976

"The Public Interest - Bank and Savings and Loan Expansion in Virginia" (with Richard D. Rogers), University of Richmond Law Review, Vol. 11, No. 3, 1977

"When Is It In the 'Public Interest' to Authorize a New Bank?", University of Richmond Law Review, Vol. 13, No. 3, 1979

"Banking Deregulation and Its Implications on the Virginia Banking Structure," William and Mary Business Review, Vol. 5, No. 1, 1983

"The Impact of Reciprocal Interstate Banking Statutes on The Performance of Virginia Bank Stocks", with William B. Harrison, Virginia Social Science Journal, Vol. 23, 1988

"The Financial Performance of New Banks in Virginia", Virginia Social Science Journal, Vol. 24, 1989

"Identifying and Managing Community Bank Performance After Deregulation", with William B. Harrison, Journal of Managerial Issues, Vol. II, No. 2, Summer 1990

"The Flotation Cost Adjustment To Utility Cost of Common Equity - Theory, Measurement and Implementation," presented at Twenty-Fifth Financial Forum, National Society of Rate of Return Analysts, Philadelphia, Pennsylvania, April 28, 1993.

Biography of Myon Edison Bristow, Dictionary of Virginia Biography, Volume 2, 2001.

Exhibit___(DCP-1)
Schedule 1

UNS GAS INC
TOTAL COST OF CAPITAL

Item	Percent	Cost			Weighted Cost		
Long-Term Debt	50.01%		6.49%			3.25%	
Common Equity	49.99%	9.50%	-	10.50%	4.75%		5.25%
Total	100.00%				7.99%		8.49%
						8.24%	**Mid-Point**

ECONOMIC INDICATORS

Year	Real GDP Growth*	Industrial Production Growth	Un-employment Rate	Consumer Price Index	Producer Price Index
			1975 - 1982 Cycle		
1975	-1.1%	-8.9%	8.5%	7.0%	6.6%
1976	5.4%	10.8%	7.7%	4.8%	3.7%
1977	5.5%	5.9%	7.0%	6.8%	6.9%
1978	5.0%	5.7%	6.0%	9.0%	9.2%
1979	2.8%	4.4%	5.8%	13.3%	12.8%
1980	-0.2%	-1.9%	7.0%	12.4%	11.8%
1981	1.8%	1.9%	7.5%	8.9%	7.1%
1982	-2.1%	-4.4%	9.5%	3.8%	3.6%
			1983 - 1991 Cycle		
1983	4.0%	3.7%	9.5%	3.8%	0.6%
1984	6.8%	9.3%	7.5%	3.9%	1.7%
1985	3.7%	1.7%	7.2%	3.8%	1.8%
1986	3.1%	0.9%	7.0%	1.1%	-2.3%
1987	2.9%	4.9%	6.2%	4.4%	2.2%
1988	3.8%	4.5%	5.5%	4.4%	4.0%
1989	3.5%	1.8%	5.3%	4.6%	4.9%
1990	1.8%	-0.2%	5.6%	6.1%	5.7%
1991	-0.5%	-2.0%	6.8%	3.1%	-0.1%
			1992 - 2001 Cycle		
1992	3.0%	3.1%	7.5%	2.9%	1.6%
1993	2.7%	3.3%	6.9%	2.7%	0.2%
1994	4.0%	5.4%	6.1%	2.7%	1.7%
1995	2.5%	4.8%	5.6%	2.5%	2.3%
1996	3.7%	4.3%	5.4%	3.3%	2.8%
1997	4.5%	7.2%	4.9%	1.7%	-1.2%
1998	4.2%	5.9%	4.5%	1.6%	0.0%
1999	4.5%	4.3%	4.2%	2.7%	2.9%
2000	3.7%	4.2%	4.0%	3.4%	3.6%
2001	0.8%	-3.4%	4.7%	1.6%	-1.6%
			Current Cycle		
2002	1.6%	-0.1%	5.8%	2.4%	1.2%
2003	2.5%	1.3%	6.0%	1.9%	4.0%
2004	3.6%	2.5%	5.5%	3.3%	4.2%
2005	2.9%	3.3%	5.1%	3.4%	5.4%
2006	2.8%	2.3%	4.6%	2.5%	1.1%
2007	2.0%	1.5%	4.6%	4.1%	6.2%
2008	1.1%	-2.2%	5.8%	0.1%	-0.9%

*GDP=Gross Domestic Product

Source: Council of Economic Advisors, Economic Indicators, various issues.

ECONOMIC INDICATORS

Year	Real GDP Growth*	Industrial Production Growth	Un-employment Rate	Consumer Price Index	Producer Price Index
2002					
1st Qtr.	2.7%	-3.8%	5.6%	2.8%	4.4%
2nd Qtr.	2.2%	-1.2%	5.9%	0.9%	-2.0%
3rd Qtr.	2.4%	0.8%	5.8%	2.4%	1.2%
4th Qtr.	0.2%	1.4%	5.9%	1.6%	0.4%
2003					
1st Qtr.	1.2%	1.1%	5.8%	4.8%	5.6%
2nd Qtr.	3.5%	-0.9%	6.2%	0.0%	-0.5%
3rd Qtr.	7.5%	-0.9%	6.1%	3.2%	3.2%
4th Qtr.	2.7%	1.5%	5.9%	-0.3%	2.8%
2004					
1st Qtr.	3.0%	2.8%	5.6%	5.2%	5.2%
2nd Qtr.	3.5%	4.9%	5.6%	4.4%	4.4%
3rd Qtr.	3.6%	4.6%	5.4%	0.8%	0.8%
4th Qtr.	2.5%	4.3%	5.4%	3.6%	7.2%
2005					
1st Qtr.	3.0%	3.8%	5.3%	4.4%	5.6%
2nd Qtr.	2.6%	3.0%	5.1%	1.6%	-0.4%
3rd Qtr.	3.8%	2.7%	5.0%	8.8%	14.0%
4th Qtr.	1.3%	2.9%	4.9%	-2.0%	4.0%
2006					
1st Qtr.	4.8%	3.4%	4.7%	4.8%	-0.2%
2nd Qtr.	2.7%	4.5%	4.6%	4.8%	5.6%
3rd Qtr.	0.8%	5.2%	4.7%	0.4%	-4.4%
4th Qtr.	1.5%	3.5%	4.5%	0.0%	3.6%
2007					
1st Qtr.	0.1%	2.5%	4.5%	4.8%	6.4%
2nd Qtr.	4.8%	1.6%	4.5%	5.2%	6.8%
3rd Qtr.	4.8%	1.8%	4.6%	1.2%	1.2%
4th Qtr.	-0.2%	2.2%	4.8%	6.4%	10.8%
2008					
1st Qtr.	0.9%	1.8%	4.9%	2.8%	9.6%
2nd Qtr.	2.8%	-0.4%	5.3%	7.6%	14.0%
3rd Qtr.	-0.5%	-3.2%	6.0%	2.8%	-0.4%
4th Qtr.	-6.3%	-6.6%	6.9%	-13.6%	-27.6%
2009					
1st Qtr.	-6.1%	-11.8%	8.1%	2.4%	-1.2%

Source: Council of Economic Advisors, Economic Indicators, various issues.

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aaa	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
			1975 - 1982 Cycle				
1975	7.86%	5.84%	7.99%	9.03%	9.44%	10.09%	10.96%
1976	6.84%	4.99%	7.61%	8.63%	8.92%	9.29%	9.82%
1977	6.83%	5.27%	7.42%	8.19%	8.43%	8.61%	9.06%
1978	9.06%	7.22%	8.41%	8.87%	9.10%	9.29%	9.62%
1979	12.67%	10.04%	9.44%	9.86%	10.22%	10.49%	10.96%
1980	15.27%	11.51%	11.46%	12.30%	13.00%	13.34%	13.95%
1981	18.89%	14.03%	13.93%	14.64%	15.30%	15.95%	16.60%
1982	14.86%	10.69%	13.00%	14.22%	14.79%	15.86%	16.45%
			1983 - 1991 Cycle				
1983	10.79%	8.63%	11.10%	12.52%	12.83%	13.66%	14.20%
1984	12.04%	9.58%	12.44%	12.72%	13.66%	14.03%	14.53%
1985	9.93%	7.48%	10.62%	11.68%	12.06%	12.47%	12.96%
1986	8.33%	5.98%	7.68%	8.92%	9.30%	9.58%	10.00%
1987	8.21%	5.82%	8.39%	9.52%	9.77%	10.10%	10.53%
1988	9.32%	6.69%	8.85%	10.05%	10.26%	10.49%	11.00%
1989	10.87%	8.12%	8.49%	9.32%	9.56%	9.77%	9.97%
1990	10.01%	7.51%	8.55%	9.45%	9.65%	9.86%	10.06%
1991	8.46%	5.42%	7.86%	8.85%	9.09%	9.36%	9.55%
			1992 - 2001 Cycle				
1992	6.25%	3.45%	7.01%	8.19%	8.55%	8.69%	8.86%
1993	6.00%	3.02%	5.87%	7.29%	7.44%	7.59%	7.91%
1994	7.15%	4.29%	7.09%	8.07%	8.21%	8.31%	8.63%
1995	8.83%	5.51%	6.57%	7.68%	7.77%	7.89%	8.29%
1996	8.27%	5.02%	6.44%	7.48%	7.57%	7.75%	8.16%
1997	8.44%	5.07%	6.35%	7.43%	7.54%	7.60%	7.95%
1998	8.35%	4.81%	5.26%	6.77%	6.91%	7.04%	7.26%
1999	8.00%	4.66%	5.65%	7.21%	7.51%	7.62%	7.88%
2000	9.23%	5.85%	6.03%	7.88%	8.06%	8.24%	8.36%
2001	6.91%	3.45%	5.02%	7.47%	7.59%	7.78%	8.02%
			Current Cycle				
2002	4.67%	1.62%	4.61%	[1]	7.19%	7.37%	8.02%
2003	4.12%	1.02%	4.01%		6.40%	6.58%	6.84%
2004	4.34%	1.38%	4.27%		6.04%	6.16%	6.40%
2005	6.19%	3.16%	4.29%		5.44%	5.65%	5.93%
2006	7.96%	4.73%	4.80%		5.84%	6.07%	6.32%
2007	8.05%	4.41%	4.63%		5.94%	6.07%	6.33%
2008	5.09%	1.48%	3.66%		6.18%	6.53%	7.25%

[1] Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, Economic Indicators; Moody's Bond Record; Federal Reserve Bulletin; various issues.

INTEREST RATES

Year	Prime Rate	US Treas T Bills 3 Month	US Treas T Bonds 10 Year	Utility Bonds Aa	Utility Bonds A	Utility Bonds Baa
2003						
Jan	4.25%	1.17%	4.05%	6.87%	7.06%	7.47%
Feb	4.25%	1.16%	3.90%	6.66%	6.93%	7.17%
Mar	4.25%	1.13%	3.81%	6.56%	6.79%	7.05%
Apr	4.25%	1.14%	3.96%	6.47%	6.64%	6.94%
May	4.25%	1.08%	3.57%	6.20%	6.36%	6.47%
June	4.00%	0.95%	3.33%	6.12%	6.21%	6.30%
July	4.00%	0.90%	3.98%	6.37%	6.57%	6.67%
Aug	4.00%	0.96%	4.45%	6.48%	6.78%	7.08%
Sept	4.00%	0.95%	4.27%	6.30%	6.56%	6.87%
Oct	4.00%	0.93%	4.29%	6.28%	6.43%	6.79%
Nov	4.00%	0.94%	4.30%	6.26%	6.37%	6.69%
Dec	4.00%	0.90%	4.27%	6.18%	6.27%	6.61%
2004						
Jan	4.00%	0.89%	4.15%	6.06%	6.15%	6.47%
Feb	4.00%	0.92%	4.08%	6.10%	6.15%	6.28%
Mar	4.00%	0.94%	3.83%	5.93%	5.97%	6.12%
Apr	4.00%	0.94%	4.35%	6.33%	6.35%	6.46%
May	4.00%	1.04%	4.72%	6.66%	6.62%	6.75%
June	4.00%	1.27%	4.73%	6.30%	6.46%	6.84%
July	4.25%	1.35%	4.50%	6.09%	6.27%	6.67%
Aug	4.50%	1.48%	4.28%	5.95%	6.14%	6.45%
Sept	4.75%	1.65%	4.13%	5.79%	5.98%	6.27%
Oct	4.75%	1.75%	4.10%	5.74%	5.94%	6.17%
Nov	5.00%	2.06%	4.19%	5.79%	5.97%	6.16%
Dec	5.25%	2.20%	4.23%	5.78%	5.92%	6.10%
2005						
Jan	5.25%	2.32%	4.22%	5.68%	5.78%	5.95%
Feb	5.50%	2.53%	4.17%	5.55%	5.61%	5.76%
Mar	5.75%	2.75%	4.50%	5.76%	5.83%	6.01%
Apr	5.75%	2.79%	4.34%	5.56%	5.64%	5.95%
May	6.00%	2.86%	4.14%	5.39%	5.53%	5.88%
June	6.25%	2.99%	4.00%	5.05%	5.40%	5.70%
July	6.25%	3.22%	4.18%	5.18%	5.51%	5.81%
Aug	6.50%	3.45%	4.26%	5.23%	5.50%	5.80%
Sept	6.75%	3.47%	4.20%	5.27%	5.52%	5.83%
Oct	6.75%	3.70%	4.46%	5.50%	5.79%	6.08%
Nov	7.00%	3.90%	4.54%	5.59%	5.88%	6.19%
Dec	7.25%	3.89%	4.47%	5.55%	5.80%	6.14%
2006						
Jan	7.50%	4.20%	4.42%	5.50%	5.75%	6.06%
Feb	7.50%	4.41%	4.57%	5.55%	5.82%	6.11%
Mar	7.75%	4.51%	4.72%	5.71%	5.98%	6.26%
Apr	7.75%	4.59%	4.99%	6.02%	6.29%	6.54%
May	8.00%	4.72%	5.11%	6.16%	6.42%	6.59%
June	8.25%	4.79%	5.11%	6.16%	6.40%	6.61%
July	8.25%	4.96%	5.09%	6.13%	6.37%	6.61%
Aug	8.25%	4.98%	4.88%	5.97%	6.20%	6.43%
Sept	8.25%	4.82%	4.72%	5.81%	6.00%	6.26%
Oct	8.25%	4.89%	4.73%	5.80%	5.98%	6.24%
Nov	8.25%	4.95%	4.60%	5.61%	5.80%	6.04%
Dec	8.25%	4.85%	4.56%	5.62%	5.81%	6.05%
2007						
Jan	8.25%	4.96%	4.76%	5.78%	5.96%	6.16%
Feb	8.25%	5.02%	4.72%	5.73%	5.90%	6.10%
Mar	8.25%	4.97%	4.56%	5.66%	5.85%	6.10%
Apr	8.25%	4.88%	4.69%	5.83%	5.97%	6.24%
May	8.25%	4.77%	4.75%	5.86%	5.99%	6.23%
June	8.25%	4.63%	5.10%	6.18%	6.30%	6.54%
July	8.25%	4.84%	5.00%	6.11%	6.25%	6.49%
Aug	8.25%	4.34%	4.67%	6.11%	6.24%	6.51%
Sept	7.75%	4.01%	4.52%	6.10%	6.18%	6.45%
Oct	7.50%	3.97%	4.53%	6.04%	6.11%	6.36%
Nov	7.50%	3.49%	4.15%	5.87%	5.97%	6.27%
Dec	7.25%	3.08%	4.10%	6.03%	6.16%	6.51%
2008						
Jan	6.00%	2.86%	3.74%	5.87%	6.02%	6.35%
Feb	6.00%	2.21%	3.74%	6.04%	6.21%	6.60%
Mar	5.25%	1.38%	3.51%	5.99%	6.21%	6.68%
Apr	5.00%	1.32%	3.68%	5.99%	6.29%	6.82%
May	5.00%	1.71%	3.88%	6.07%	6.27%	6.79%
June	5.00%	1.90%	4.10%	6.19%	6.38%	6.93%
July	5.00%	1.72%	4.01%	6.13%	6.40%	6.97%
Aug	5.00%	1.79%	3.89%	6.09%	6.37%	6.98%
Sept	5.00%	1.46%	3.69%	6.13%	6.49%	7.15%
Oct	4.00%	0.84%	3.81%	6.95%	7.56%	8.58%
Nov	4.00%	0.30%	3.53%	6.83%	7.60%	8.98%
Dec	3.25%	0.04%	2.42%	5.93%	6.54%	8.13%
2009						
Jan	3.25%	0.12%	2.52%	6.01%	6.39%	7.90%
Feb	3.25%	0.31%	2.87%	6.11%	6.30%	7.74%
Mar	3.25%	0.25%	2.82%	6.14%	6.42%	8.00%
Apr	3.25%	0.17%	2.93%	6.20%	6.48%	8.03%

Note: Moody's has not published Aaa utility bond yields since 2001.

Sources: Council of Economic Advisors, *Economic Indicators*; Moody's Bond Record; Federal Reserve Bulletin; various issues.

STOCK PRICE INDICATORS

Year	S&P Composite [1]	NASDAQ Composite [1]	DJIA	S&P D/P	S&P E/P
		1975 - 1982 Cycle			
1975			802.49	4.31%	9.15%
1976			974.92	3.77%	8.90%
1977			894.63	4.62%	10.79%
1978			820.23	5.28%	12.03%
1979			844.40	5.47%	13.46%
1980			891.41	5.26%	12.66%
1981			932.92	5.20%	11.96%
1982			884.36	5.81%	11.60%
		1983 - 1991 Cycle			
1983			1,190.34	4.40%	8.03%
1984			1,178.48	4.64%	10.02%
1985			1,328.23	4.25%	8.12%
1986			1,792.76	3.49%	6.09%
1987			2,275.99	3.08%	5.48%
1988	[1]	[1]	2,060.82	3.64%	8.01%
1989	322.84		2,508.91	3.45%	7.41%
1990	334.59		2,678.94	3.61%	6.47%
1991	376.18	491.69	2,929.33	3.24%	4.79%
		1992 - 2001 Cycle			
1992	415.74	599.26	3,284.29	2.99%	4.22%
1993	451.21	715.16	3,522.06	2.78%	4.46%
1994	460.42	751.65	3,793.77	2.82%	5.83%
1995	541.72	925.19	4,493.76	2.56%	6.09%
1996	670.50	1,164.96	5,742.89	2.19%	5.24%
1997	873.43	1,469.49	7,441.15	1.77%	4.57%
1998	1,085.50	1,794.91	8,625.52	1.49%	3.46%
1999	1,327.33	2,728.15	10,464.88	1.25%	3.17%
2000	1,427.22	3,783.67	10,734.90	1.15%	3.63%
2001	1,194.18	2,035.00	10,189.13	1.32%	2.95%
		Current Cycle			
2002	993.94	1,539.73	9,226.43	1.61%	2.92%
2003	965.23	1,647.17	8,993.59	1.77%	3.84%
2004	1,130.65	1,986.53	10,317.39	1.72%	4.89%
2005	1,207.23	2,099.32	10,547.67	1.83%	5.36%
2006	1,310.46	2,263.41	11,408.67	1.87%	5.78%
2007	1,477.19	2,578.47	13,169.98	1.86%	5.29%
2008	1,220.04	2,161.65	11,252.62	2.37%	3.55%

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAQ Composite prior to 1991.

Source: Council of Economic Advisors, Economic Indicators, various issues.

STOCK PRICE INDICATORS

YEAR	S&P Composite	NASDAQ Composite	DJIA	S&P D/P	S&P E/P
2002					
1st Qtr.	1,131.56	1,879.85	10,105.27	1.39%	2.15%
2nd Qtr.	1,068.45	1,641.53	9,912.70	1.49%	2.70%
3rd Qtr.	894.65	1,308.17	8,487.59	1.76%	3.68%
4th Qtr.	887.91	1,346.07	8,400.17	1.79%	3.14%
2003					
1st Qtr.	860.03	1,350.44	8,122.83	1.89%	3.57%
2nd Qtr.	938.00	1,521.92	8,684.52	1.75%	3.55%
3rd Qtr.	1,000.50	1,765.96	9,310.57	1.74%	3.87%
4th Qtr.	1,056.42	1,934.71	9,856.44	1.69%	4.38%
2004					
1st Qtr.	1,133.29	2,041.95	10,488.43	1.64%	4.62%
2nd Qtr.	1,122.87	1,984.13	10,289.04	1.71%	4.92%
3rd Qtr.	1,104.15	1,872.90	10,129.85	1.79%	5.18%
4th Qtr.	1,162.07	2,050.22	10,362.25	1.75%	4.83%
2005					
1st Qtr.	1,191.98	2,056.01	10,648.48	1.77%	5.11%
2nd Qtr.	1,181.65	2,012.24	10,382.35	1.85%	5.32%
3rd Qtr.	1,225.91	2,144.61	10,532.24	1.83%	5.42%
4th Qtr.	1,262.07	2,246.09	10,827.79	1.86%	5.60%
2006					
1st Qtr.	1,283.04	2,287.97	10,996.04	1.85%	5.61%
2nd Qtr.	1,281.77	2,240.46	11,188.84	1.90%	5.86%
3rd Qtr.	1,288.40	2,141.97	11,274.49	1.91%	5.88%
4th Qtr.	1,389.48	2,390.26	12,175.30	1.81%	5.75%
2007					
1st Qtr.	1,425.30	2,444.85	12,470.97	1.84%	5.85%
2nd Qtr.	1,496.43	2,552.37	13,214.26	1.82%	5.65%
3rd Qtr.	1,490.81	2,609.68	13,488.43	1.86%	5.15%
4th Qtr.	1,494.09	2,701.59	13,502.95	1.91%	4.51%
2008					
1st Qtr.	1,350.19	2,332.91	12,383.86	2.11%	4.57%
2nd Qtr.	1,371.65	2,426.26	12,508.59	2.10%	4.01%
3rd Qtr.	1,251.94	2,290.87	11,322.40	2.29%	3.94%
4th Qtr.	909.80	1,599.64	8,795.61	2.98%	1.65%
2009					
1st Qtr.	809.31	1,485.14	7,774.06	3.00%	

[1] Note: this source did not publish the S&P Composite prior to 1988 and the NASDAQ Composite prior to 1991.

Source: *Council of Economic Advisors, Economic Indicators, various issues.*

Exhibit___(DCP-1)
Schedule 3

UNISOURCE ENERGY CORPORATION
SEGMENT FINANCIAL INFORMATION
2006 - 2008
($millions)

Segment	Operating Revenues	Operating Income	Total Assets
		2006	
Tucson Electric Power Co	$989	$216	$2,623
	75.6%	90.0%	82.3%
UNS Gas	$162	$13	$253
	12.4%	5.4%	7.9%
UNS Electric	$160	$13	$195
	12.2%	5.4%	6.1%
All Other	$14		$1,038
	1.1%	0.0%	32.6%
Unisource Energy	$1,308	$240	$3,187
		2007	
Tucson Electric Power Co	$1,071	$189	$2,573
	77.6%	88.7%	80.8%
UNS Gas	$151	$12	$276
	10.9%	5.6%	8.7%
UNS Electric	$169	$12	$231
	12.2%	5.6%	7.3%
All Other	$12		$1,077
	0.9%	0.0%	33.8%
Unisource Energy	$1,381	$213	$3,186
		2008	
Tucson Electric Power Co	$1,079	$107	$2,842
	77.2%	73.8%	81.0%
UNS Gas	$174	$20	$294
	12.4%	13.8%	8.4%
UNS Electric	$195	$12	$285
	13.9%	8.3%	8.1%
All Other	$23		$1,061
	1.6%	0.0%	30.2%
Unisource Energy	$1,398	$145	$3,510

UNS Gas, TEP and UNS Electric figures do not total to Unisource Energy cosolidated figures due to other activities of Unisource Energy.

Source: Unisource Energy Corporation 2008 Form 10-K.

UNS GAS
CAPITAL STRUCTURE RATIOS
2003 - 2008
($millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2004	$58.8	$100.0	
	37.0%	63.0%	0.0%
	37.0%	63.0%	
2005	$79.8	$100.0	
	44.4%	55.6%	0.0%
	44.4%	55.6%	
2006	$84.2	$100.0	
	45.7%	54.3%	0.0%
	45.7%	54.3%	
2007	$88.3	$100.0	
	46.9%	53.1%	0.0%
	46.9%	53.1%	
2008	$96.7	$100.0	
	49.2%	50.8%	0.0%
	49.2%	50.8%	

Source: Response to DP 5.2

UNISOURCE ENERGY CORP
CAPITAL STRUCTURE RATIOS
2003 - 2008
($millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
2004	$581	$1,258	$0
	31.6%	68.4%	0.0%
	31.6%	68.4%	
2005	$617	$1,212	$5
	33.6%	66.1%	0.3%
	33.7%	66.3%	
2006	$654	$1,171	$50
	34.9%	62.5%	2.7%
	35.8%	64.2%	
2007	$690	$994	$10
	40.7%	58.7%	0.6%
	41.0%	59.0%	
2008	$679	$1,314	$10
	33.9%	65.6%	0.5%
	34.1%	65.9%	

Source: Unisource Energy Corporation 2008 Form 10-K.
Item 6. - Selected Consolidated Financial Data

UNISOURCE ENERGY AND UTILITY SUBSIDIARIES
CAPITAL STRUCTURE RATIOS
2008
($millions)

YEAR	COMMON EQUITY	LONG-TERM DEBT	SHORT-TERM DEBT
Unisource	$679.3	$1,313.6	$10.0
Energy	33.9%	65.6%	0.5%
consolidated	34.1%	65.9%	
UNS Gas	$96.7	$100.0	
	49.2%	50.8%	0.0%
	49.2%	50.8%	
UNS Electric	$83.8	$108.0	
	43.7%	56.3%	0.0%
	43.7%	56.3%	
TEP	$583.6	$903.6	$10.0
	39.0%	60.4%	0.7%
	39.2%	60.8%	

Source for Unisource Energy Consolidated and TEP is 2008 10-K
Source for UNS Gas and UNS Electric is Response to DP 5.2

Exhibit___(DCP-1)
Schedule 5

PROXY GROUPS
COMMON EQUITY RATIOS

COMPANY	2004	2005	2006	2007	2008	Average	2012-2014
Parcell Proxy Group							
Avista Corp.	41.9%	40.6%	46.3%	59.0%	50.5%	47.0%	52.5%
Hawaiian Electric Industries, Inc	51.0%	53.3%	48.6%	51.0%	52.5%	51.3%	55.5%
Northeast Utilities	34.0%	35.1%	39.7%	39.2%	38.1%	37.2%	44.5%
Pinnacle West Capital Corp.	53.3%	56.8%	51.6%	53.0%	53.0%	53.5%	52.5%
Pepco Holdings, Inc.	39.6%	42.3%	45.1%	45.9%	48.5%	44.3%	48.5%
TECO Energy, Inc.	24.9%	30.0%	35.0%	39.0%	38.5%	33.5%	42.0%
Westar Energy, Inc.	45.5%	47.2%	49.3%	48.9%	49.9%	48.2%	54.0%
Average	41.5%	43.6%	45.1%	48.0%	47.3%	45.0%	49.9%
Grant Comparable Company Group							
AGL Resources	46.0%	48.1%	49.8%	49.8%	49.7%	48.7%	55.0%
Atmos Energy Corp	56.8%	42.3%	43.0%	48.0%	49.2%	47.9%	51.0%
Laclede Group	48.3%	51.8%	50.4%	54.6%	55.5%	52.1%	53.0%
New Jersey Resources Corp	59.7%	58.0%	65.2%	62.7%	61.5%	61.4%	67.0%
NICOR Inc	60.1%	62.5%	63.7%	69.0%	68.4%	64.7%	74.0%
Northwest Natural Gas Co	54.0%	53.0%	53.7%	53.7%	55.1%	53.9%	53.0%
Piedmont Natural Gas Co	56.4%	58.6%	51.7%	51.6%	52.8%	54.2%	53.0%
South Jersey Industries	51.0%	55.1%	55.3%	57.3%	60.8%	55.9%	59.5%
Southwest Gas Corp	35.8%	36.2%	39.4%	41.9%	44.7%	39.6%	49.0%
WGL Holdings	57.2%	58.6%	60.4%	60.3%	62.4%	59.8%	64.5%
Average	52.5%	52.4%	53.3%	54.9%	56.0%	53.8%	57.9%

Source: Value Line Investment Survey.

PROXY COMPANIES

Company	Market Capitalization ($ millions)	Percent Reg Elec or Gas Revenues	S&P Bond Rating	Moody's Bond Rating	Common Equity Ratio	Value Line Safety
Unisource Energy	$900	85%	BBB	Baa2	27%	3
Parcell Proxy Group						
Avista Corp.	$1,100	50%	BBB+	Baa2	52%	3
Hawaiian Electric Industries, Inc.	$1,900	85%	BBB+	Baa2	53%	2
Northeast Utilities	$3,600	81%	BBB+	Baa1	38%	3
Pinnacle West Capital Corp.	$3,500	93%	BBB-	Baa2	53%	2
Pepco Holdings, Inc.	$3,400	73%	BBB+	A3	44%	3
TECO Energy, Inc.	$2,200	62%	BBB-	Baa2	39%	3
Westar Energy, Inc.	$1,800	70%	BBB-	Baa2	50%	2
Grant Comparable Company Group						
AGL Resources	$2,000	56%	A-	A3	39%	2
Atmos Energy Corp	$1,900	52%	BBB+	Baa3	46%	2
Laclede Group	$850	50%	BBB+	Baa1	57%	2
New Jersey Resources Corp	$1,400	30%	NR	NR	49%	1
NICOR Inc	$1,300	85%	AA	A1	44%	3
Northwest Natural Gas Co	$1,000	98%	AA-	A2	45%	1
Piedmont Natural Gas Co	$1,700	75%	A	A3	43%	2
South Jersey Industries	$1,000	58%	A	A3	47%	2
Southwest Gas Corp	$800	84%	BBB-	Baa3	43%	3
WGL Holdings	$1,500	59%	AA-	A2	50%	1

Sources: AUS Utility Reports, Value Line.

COMPARISON COMPANIES
DIVIDEND YIELD

COMPANY	February - April, 2009 DPS	HIGH	LOW	AVERAGE	YIELD
Parcell Proxy Group					
Avista Corp.	$0.72	$19.52	$12.67	$16.10	4.5%
Hawaiian Electric Industries, Inc.	$1.24	$22.73	$12.09	$17.41	7.1%
Northeast Utilities	$0.95	$25.25	$19.01	$22.13	4.3%
Pinnacle West Capital Corp.	$2.10	$35.13	$22.32	$28.73	7.3%
Pepco Holdings, Inc.	$1.08	$18.71	$10.07	$14.39	7.5%
TECO Energy, Inc.	$0.80	$12.71	$8.41	$10.56	7.6%
Westar Energy, Inc.	$1.20	$20.84	$14.86	$17.85	6.7%
Average					**6.4%**
Grant Comparable Company Group					
AGL Resources	$1.72	$34.93	$24.02	$29.48	5.8%
Atmos Energy Corp	$1.32	$26.17	$20.07	$23.12	5.7%
Laclede Group	$1.54	$47.20	$33.81	$40.51	3.8%
New Jersey Resources Corp	$1.24	$42.37	$29.95	$36.16	3.4%
NICOR Inc	$1.86	$36.34	$27.50	$31.92	5.8%
Northwest Natural Gas Co	$1.58	$45.66	$37.71	$41.69	3.8%
Piedmont Natural Gas Co	$1.08	$27.55	$20.68	$24.12	4.5%
South Jersey Industries	$1.19	$38.68	$31.98	$35.33	3.4%
Southwest Gas Corp	$0.90	$26.38	$17.08	$21.73	4.1%
WGL Holdings	$1.47	$35.52	$28.89	$32.21	4.6%
Average					**4.5%**

Source: Yahoo! Finance.

COMPARISON COMPANIES
RETENTION GROWTH RATES

COMPANY	2004	2005	2006	2007	2008	Average	2009	2010	2012-'14	Average
Parcell Proxy Group										
Avista Corp.	1.4%	2.4%	4.9%	0.8%	3.7%	2.6%	4.0%	3.5%	2.5%	3.3%
Hawaiian Electric Industries, Inc.	1.1%	1.5%	0.7%	0.8%	0.5%	0.9%	0.5%	2.5%	3.0%	2.0%
Northeast Utilities	1.6%	1.5%	0.3%	4.3%	5.3%	2.6%	4.5%	4.5%	4.5%	4.5%
Pinnacle West Capital Corp.	2.3%	1.0%	3.4%	2.5%	0.3%	1.9%	1.0%	2.0%	3.0%	2.0%
Pepco Holdings, Inc.	2.5%	2.4%	1.5%	2.3%	4.2%	2.6%	2.0%	3.0%	3.5%	2.8%
TECO Energy, Inc.	0.0%	3.3%	5.0%	5.1%	0.0%	2.7%	2.5%	4.0%	4.5%	3.7%
Westar Energy, Inc.	3.2%	4.3%	5.5%	4.3%	1.2%	3.7%	2.5%	2.5%	3.0%	2.7%
Average						**2.4%**				**3.0%**
Grant Comparable Company Group										
AGL Resources	5.6%	6.2%	6.3%	5.3%	5.0%	5.7%	4.5%	5.0%	6.0%	5.2%
Atmos Energy Corp	1.7%	2.3%	3.6%	3.0%	3.1%	2.7%	3.5%	3.5%	4.0%	3.7%
Laclede Group	2.7%	3.1%	5.1%	4.3%	5.2%	4.1%	6.0%	4.0%	5.0%	5.0%
New Jersey Resources Corp	7.8%	8.5%	6.3%	3.6%	9.5%	7.1%	6.5%	7.0%	5.5%	6.3%
NICOR Inc	2.1%	2.3%	5.2%	5.4%	3.6%	3.7%	3.0%	4.5%	5.5%	4.3%
Northwest Natural Gas Co	2.7%	3.7%	4.5%	6.0%	4.7%	4.3%	4.5%	4.5%	4.5%	4.5%
Piedmont Natural Gas Co	3.7%	3.6%	2.8%	3.5%	3.9%	3.5%	4.0%	5.0%	6.0%	5.0%
South Jersey Industries	5.9%	6.2%	10.2%	6.7%	6.8%	7.2%	7.0%	6.5%	7.0%	6.8%
Southwest Gas Corp	4.3%	2.2%	5.2%	4.8%	2.1%	3.7%	2.5%	3.5%	4.5%	3.5%
WGL Holdings	4.1%	4.6%	3.2%	3.5%	5.0%	4.1%	4.5%	4.5%	4.5%	4.5%
Average						**4.6%**				**4.9%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
PER SHARE GROWTH RATES

COMPANY	5-Year Historic Growth Rates				Est'd '06-'08 to '12-'14 Growth Rates			
	EPS	DPS	BVPS	Average	EPS	DPS	BVPS	Average
Parcell Proxy Group								
Avista Corp.	4.0%	5.0%	3.0%	4.0%	6.5%	12.5%	3.5%	7.5%
Hawaiian Electric Industries, Inc.	-6.0%	0.0%	1.0%	-1.7%	7.0%	0.0%	2.5%	3.2%
Northeast Utilities	3.0%	8.5%	2.0%	4.5%	8.0%	6.5%	5.0%	6.5%
Pinnacle West Capital Corp.	-1.0%	5.0%	3.0%	2.3%	3.0%	1.0%	1.0%	1.7%
Pepco Holdings, Inc.	-2.0%	17.5%	1.5%	5.7%	3.0%		2.5%	2.8%
TECO Energy, Inc.	-5.0%	-9.0%	-6.5%	-6.8%	4.5%	2.5%	4.5%	3.8%
Westar Energy, Inc.	32.0%	-5.0%	-4.5%	7.5%	4.0%	4.5%	6.0%	4.8%
Average				**2.2%**				**4.3%**
Grant Comparable Company Group								
AGL Resources	11.5%	6.5%	11.5%	9.8%	3.0%	2.5%	0.5%	2.0%
Atmos Energy Corp	5.0%	1.5%	7.5%	4.7%	4.0%	1.5%	4.0%	3.2%
Laclede Group	9.5%	1.5%	5.5%	5.5%	3.5%	2.5%	5.5%	3.8%
New Jersey Resources Corp	7.5%	5.0%	11.5%	8.0%	5.5%	5.5%	8.5%	6.5%
NICOR Inc	1.0%	0.5%	4.0%	1.8%	2.5%	0.0%	4.5%	2.3%
Northwest Natural Gas Co	6.5%	2.0%	3.5%	4.0%	7.0%	5.5%	3.5%	5.3%
Piedmont Natural Gas Co	6.5%	4.5%	6.0%	5.7%	7.5%	3.5%	5.0%	5.3%
South Jersey Industries	12.5%	4.5%	12.5%	9.8%	5.5%	7.0%	4.5%	5.7%
Southwest Gas Corp	8.0%	0.5%	4.0%	4.2%	4.5%	5.0%	2.5%	4.0%
WGL Holdings	4.0%	1.5%	4.5%	3.3%	4.0%	2.5%	5.0%	3.8%
Average				**5.7%**				**4.2%**

Source: Value Line Investment Survey.

COMPARISON COMPANIES
DCF COST RATES

COMPANY	ADJUSTED YIELD	HISTORIC RETENTION GROWTH	PROSPECTIVE RETENTION GROWTH	HISTORIC PER SHARE GROWTH	PROSPECTIVE PER SHARE GROWTH	FIRST CALL EPS GROWTH	AVERAGE GROWTH	DCF RATES
Parcell Proxy Group								
Avista Corp.	4.6%	2.6%	3.3%	4.0%	7.5%	4.7%	4.4%	9.0%
Hawaiian Electric Industries, Inc.	7.2%	0.9%	2.0%		3.2%	4.8%	2.7%	9.9%
Northeast Utilities	4.4%	2.6%	4.5%	4.5%	6.5%	7.4%	5.1%	9.5%
Pinnacle West Capital Corp.	7.4%	1.9%	2.0%	2.3%	1.7%	4.5%	2.5%	9.9%
Pepco Holdings, Inc.	7.6%	2.6%	2.8%	5.7%	2.8%	3.7%	3.5%	11.1%
TECO Energy, Inc.	7.8%	2.7%	3.7%		3.8%	8.7%	4.7%	12.5%
Westar Energy, Inc.	6.9%	3.7%	2.7%	7.5%	4.8%	3.6%	4.5%	11.3%
Mean	6.6%	2.4%	3.0%	4.8%	4.3%	5.3%	3.9%	**10.5%**
Median	7.2%	2.6%	2.8%	4.5%	3.8%	4.7%	4.4%	**9.9%**
Composite - Mean		**9.0%**	9.6%	11.4%	10.9%	**11.9%**	10.5%	
Composite - Median		**9.8%**	10.1%	11.7%	11.1%	**11.9%**	11.6%	
Grant Comparable Company Group								
AGL Resources	6.0%	5.7%	5.2%	9.8%	2.0%	5.3%	5.6%	11.6%
Atmos Energy Corp	5.8%	2.7%	3.7%	4.7%	3.2%	5.0%	3.8%	9.7%
Laclede Group	3.9%	4.1%	5.0%	5.5%	3.8%	3.5%	4.4%	8.3%
New Jersey Resources Corp	3.5%	7.1%	6.3%	8.0%	6.5%	7.0%	7.0%	10.5%
NICOR Inc	5.9%	3.7%	4.3%	1.8%	2.3%	4.5%	3.3%	9.3%
Northwest Natural Gas Co	3.9%	4.3%	4.5%	4.0%	5.3%	4.8%	4.6%	8.5%
Piedmont Natural Gas Co	4.6%	3.5%	5.0%	5.7%	5.3%	7.0%	5.3%	9.9%
South Jersey Industries	3.5%	7.2%	6.8%	9.8%	5.7%	7.0%	7.3%	10.8%
Southwest Gas Corp	4.2%	3.7%	3.5%	4.2%	4.0%	6.0%	4.3%	8.5%
WGL Holdings	4.7%	4.1%	4.5%	3.3%	3.8%	4.0%	3.9%	8.6%
Mean	4.6%	4.6%	4.9%	5.7%	4.2%	5.4%	5.0%	**9.6%**
Median	4.4%	4.1%	4.8%	5.1%	3.9%	5.1%	4.5%	**9.5%**
Composite - Mean		9.2%	9.5%	**10.3%**	**8.8%**	10.0%	9.6%	
Composite - Median		8.5%	9.2%	**9.5%**	**8.3%**	**9.5%**	8.9%	

Sources: Prior pages of this schedule.

Exhibit___(DCP-1)
Schedule 8

STANDARD & POOR'S 500 COMPOSITE
20-YEAR U.S. TREASURY BOND YIELDS
RISK PREMIUMS

Year	EPS	BVPS	ROE	20-YEAR T-BOND YIELD	RISK PREMIUM
1977		$79.07			
1978	$12.33	$85.35	15.00%	7.90%	7.10%
1979	$14.86	$94.27	16.55%	8.86%	7.69%
1980	$14.82	$102.48	15.06%	9.97%	5.09%
1981	$15.36	$109.43	14.50%	11.55%	2.95%
1982	$12.64	$112.46	11.39%	13.50%	-2.11%
1983	$14.03	$116.93	12.23%	10.38%	1.85%
1984	$16.64	$122.47	13.90%	11.74%	2.16%
1985	$14.61	$125.20	11.80%	11.25%	0.55%
1986	$14.48	$126.82	11.49%	8.98%	2.51%
1987	$17.50	$134.04	13.42%	7.92%	5.50%
1988	$23.75	$141.32	17.25%	8.97%	8.28%
1989	$22.87	$147.26	15.85%	8.81%	7.04%
1990	$21.73	$153.01	14.47%	8.19%	6.28%
1991	$16.29	$158.85	10.45%	8.22%	2.23%
1992	$19.09	$149.74	12.37%	7.29%	5.08%
1993	$21.89	$180.88	13.24%	7.17%	6.07%
1994	$30.60	$193.06	16.37%	6.59%	9.78%
1995	$33.96	$215.51	16.62%	7.60%	9.02%
1996	$38.73	$237.08	17.11%	6.18%	10.93%
1997	$39.72	$249.52	16.33%	6.64%	9.69%
1998	$37.71	$266.40	14.62%	5.83%	8.79%
1999	$48.17	$290.68	17.29%	5.57%	11.72%
2000	$50.00	$325.80	16.22%	6.50%	9.72%
2001	$24.69	$338.37	7.43%	5.53%	1.90%
2002	$27.59	$321.72	8.36%	5.59%	2.77%
2003	$48.73	$367.17	14.15%	4.80%	9.35%
2004	$58.55	$414.75	14.98%	5.02%	9.96%
2005	$69.93	$453.06	16.12%	4.69%	11.43%
2006	$81.51	$504.39	17.03%	4.68%	12.35%
2007	$66.17	$529.59	12.80%	4.86%	7.94%
Average					**6.45%**

Source: Standard & Poor's Analysts' Handbook, Ibbotson Associates Handbook.

COMPARISON COMPANIES
CAPM COST RATES

COMPANY	RISK-FREE RATE	BETA	RISK PREMIUM	CAPM RATES
Parcell Proxy Group				
Avista Corp.	3.82%	0.70	5.32%	7.5%
Hawaiian Electric Industries, Inc.	3.82%	0.60	5.32%	7.0%
Northeast Utilities	3.82%	0.70	5.32%	7.5%
Pinnacle West Capital Corp.	3.82%	0.70	5.32%	7.5%
Pepco Holdings, Inc.	3.82%	0.80	5.32%	8.1%
TECO Energy, Inc.	3.82%	0.80	5.32%	8.1%
Westar Energy, Inc.	3.82%	0.75	5.32%	7.8%
Mean				**7.7%**
Median				**7.5%**
Grant Comparable Company Group				
AGL Resources	3.82%	0.75	5.32%	7.8%
Atmos Energy Corp	3.82%	0.60	5.32%	7.0%
Laclede Group	3.82%	0.65	5.32%	7.3%
New Jersey Resources Corp	3.82%	0.65	5.32%	7.3%
NICOR Inc	3.82%	0.75	5.32%	7.8%
Northwest Natural Gas Co	3.82%	0.60	5.32%	7.0%
Piedmont Natural Gas Co	3.82%	0.65	5.32%	7.3%
South Jersey Industries	3.82%	0.65	5.32%	7.3%
Southwest Gas Corp	3.82%	0.70	5.32%	7.5%
WGL Holdings	3.82%	0.65	5.32%	7.3%
Mean				**7.4%**
Median				**7.3%**

Sources: Value Line Investment Survey, Standard & Poor's Analysts' Handbook, Federal Reserve.

20-year Treasury Bonds

Month	Rate
Feb-09	3.83%
Mar-09	3.78%
Apr-09	3.84%

COMPARISON COMPANIES
RATES OF RETURN ON AVERAGE COMMON EQUITY

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	1992-2001 Average	2002-2008 Average	2009	2010	2012-14
Parcell Proxy Group																						
Avista Corp.	11.7%	12.2%	10.5%	11.2%	10.6%	15.0%	10.2%	1.1%	13.4%	7.9%	4.5%	6.7%	4.6%	5.8%	8.8%	4.1%	8.2%	10.4%	6.1%	8.0%	8.0%	8.0%
Hawaiian Electric Industries, In	10.9%	10.5%	11.1%	11.0%	10.5%	10.9%	11.5%	11.1%	9.8%	12.4%	11.9%	11.1%	9.3%	9.7%	9.3%	7.7%	8.1%	11.0%	9.6%	8.5%	10.0%	10.5%
Northeast Utilities	12.6%	9.4%	12.6%	11.9%	0.1%	-6.2%	-2.3%	-7.3%	-1.3%	8.6%	6.4%	7.1%	5.1%	5.4%	4.5%	8.6%	9.8%	3.8%	6.7%	8.5%	9.5%	8.5%
Pinnacle West Capital Corp.	10.7%	10.9%	10.2%	10.6%	11.2%	11.9%	11.5%	12.3%	12.4%	12.8%	8.6%	8.3%	8.2%	6.7%	9.2%	8.5%	7.9%	11.5%	8.2%	7.5%	8.0%	9.0%
Pepco Holdings, Inc.	10.6%	12.0%	10.8%	10.5%	11.7%	10.5%	11.3%	11.7%	8.9%	11.9%	9.8%	7.6%	8.3%	8.1%	7.1%	7.9%	9.0%	11.0%	8.2%	7.5%	8.5%	8.5%
TECO Energy, Inc.	16.1%	15.1%	14.5%	16.6%	16.5%	14.8%	13.5%	13.8%	17.4%	17.2%	13.5%	-0.7%	9.2%	14.2%	14.7%	14.3%	8.9%	15.6%	10.6%	11.0%	12.0%	12.0%
Westar Energy, Inc.	11.0%	12.4%	10.7%	11.1%	10.4%	-1.6%	7.1%	5.2%	3.2%	-2.2%	5.0%	10.6%	7.7%	9.6%	11.1%	10.0%	6.6%	6.7%	8.7%	8.0%	8.0%	8.0%
Average	11.9%	11.8%	11.5%	11.8%	10.1%	7.9%	9.0%	6.9%	9.1%	9.8%	8.5%	7.2%	7.5%	8.5%	9.2%	8.7%	8.4%	**10.0%**	**8.3%**	**8.4%**	**9.1%**	**9.2%**
Median	11.0%	12.0%	10.8%	11.1%	10.6%	10.9%	11.3%	11.1%	9.8%	11.9%	8.6%	7.6%	8.2%	8.1%	9.2%	8.5%	8.2%	**11.1%**	**8.3%**	**8.0%**	**8.5%**	**8.5%**
Grant Comparable Company Group																						
AGL Resources	11.8%	11.0%	11.6%	13.1%	13.2%	12.7%	12.6%	7.9%	11.2%	12.7%	14.7%	15.3%	13.9%	13.3%	13.6%	12.8%	12.5%	11.8%	13.7%	12.5%	13.0%	14.5%
Atmos Energy Corp	10.7%	12.7%	10.0%	12.2%	14.4%	12.3%	15.8%	6.7%	8.5%	11.1%	10.3%	11.2%	9.1%	9.1%	10.0%	9.2%	9.0%	11.4%	9.7%	9.0%	8.5%	9.5%
Laclede Group	9.9%	13.4%	11.5%	10.0%	14.0%	13.2%	11.0%	10.0%	9.1%	10.6%	7.8%	11.8%	11.2%	11.1%	13.1%	12.0%	12.6%	11.3%	11.4%	12.5%	10.5%	11.0%
New Jersey Resources Corp	12.2%	11.8%	13.0%	13.3%	13.9%	14.5%	14.7%	15.0%	15.1%	15.2%	15.9%	16.8%	15.8%	16.2%	14.6%	10.2%	16.5%	13.9%	15.1%	13.5%	13.0%	11.0%
NICOR Inc	15.3%	15.3%	15.7%	14.6%	17.0%	16.9%	14.7%	15.7%	18.2%	18.8%	17.3%	12.4%	13.0%	12.8%	15.2%	14.9%	12.5%	16.2%	14.0%	11.0%	12.5%	12.0%
Northwest Natural Gas Co	6.0%	13.7%	12.2%	11.4%	13.2%	11.2%	6.3%	10.1%	10.2%	10.3%	8.7%	9.2%	9.3%	10.1%	10.9%	12.4%	11.2%	10.5%	10.2%	11.0%	11.0%	11.0%
Piedmont Natural Gas Co	14.1%	13.8%	12.2%	12.3%	13.2%	13.8%	13.6%	12.1%	12.5%	12.0%	10.8%	12.2%	12.4%	11.6%	11.0%	11.8%	12.4%	13.0%	11.7%	12.5%	13.5%	13.5%
South Jersey Industries	11.8%	11.0%	8.5%	11.4%	11.1%	11.9%	10.1%	15.6%	15.4%	15.3%	14.0%	13.1%	13.4%	13.2%	17.2%	13.3%	13.5%	12.2%	13.9%	13.5%	13.5%	14.5%
Southwest Gas Corp	5.1%	3.9%	7.5%	0.6%	1.7%	5.4%	10.4%	7.5%	7.3%	6.7%	6.6%	6.2%	8.8%	6.5%	9.7%	8.8%	6.1%	5.6%	7.5%	6.0%	7.5%	9.0%
WGL Holdings	12.5%	12.1%	12.6%	12.4%	15.0%	14.1%	11.3%	10.3%	11.9%	11.9%	7.1%	14.4%	11.9%	12.1%	10.8%	11.0%	12.0%	12.4%	11.3%	12.0%	11.5%	11.0%
Average	10.9%	11.9%	11.5%	11.1%	12.7%	12.6%	12.0%	11.1%	11.9%	12.5%	11.3%	12.3%	11.9%	11.6%	12.6%	11.6%	11.8%	**11.8%**	**11.9%**	**11.4%**	**11.5%**	**11.7%**
Median	11.8%	12.4%	11.9%	12.3%	13.6%	12.9%	11.9%	10.2%	11.5%	11.9%	10.6%	12.3%	12.2%	11.9%	12.0%	11.9%	12.4%	**12.1%**	**11.9%**	**12.3%**	**12.0%**	**11.0%**

Source: Calculations made from data contained in Value Line Investment Survey.

COMPARISON COMPANIES
MARKET TO BOOK RATIOS

COMPANY	1992	1993	1994	1995	1996	1997	1998	1999	2000	2001	2002	2003	2004	2005	2006	2007	2008	1992-2001 Average	2002-2008 Average
Parcell Proxy Group																			
Avista Corp.	151%	163%	133%	125%	145%	162%	163%	152%	317%	114%	85%	94%	111%	115%	135%	126.7%	110%	163%	111%
Hawaiian Electric Industries,	171%	154%	141%	149%	147%	147%	154%	132%	127%	145%	153%	151%	179%	181%	192%	166.4%	164%	147%	169%
Northeast Utilities	154%	149%	127%	124%	95%	64%	91%	113%	136%	129%	99%	95%	106%	108%	131%	162.5%	128%	118%	119%
Pinnacle West Capital Corp.	116%	125%	99%	116%	133%	152%	180%	143%	145%	154%	116%	114%	130%	130%	129%	127.1%	97%	136%	120%
Pepco Holdings, Inc.	160%	162%	135%	138%	161%	151%	161%	166%	139%	124%	110%	103%	109%	122%	129%	141.3%	110%	150%	118%
TECO Energy, Inc.	243%	268%	224%	238%	241%	234%	247%	210%	223%	222%	135%	111%	174%	243%	202%	187.5%	174%	235%	175%
Westar Energy, Inc.	144%	152%	130%	129%	126%	131%	128%	89%	74%	78%	67%	109%	132%	142%	139%	139.8%	106%	118%	119%
Average	163%	168%	141%	146%	150%	149%	160%	144%	166%	138%	109%	111%	134%	149%	151%	150%	127%	**152%**	**133%**
Median	154%	154%	133%	129%	145%	151%	161%	143%	139%	129%	110%	109%	130%	130%	135%	141%	110%	**144%**	**124%**
Grant Comparable Company Group																			
AGL Resources	181%	195%	169%	172%	189%	183%	183%	169%	168%	184%	171%	188%	184%	191%	186%	188.2%	146.0%	179%	179%
Atmos Energy Corp	158%	194%	186%	196%	248%	241%	246%	216%	167%	170%	150%	152%	147%	145%	146%	136.1%	109.8%	202%	141%
Laclede Group	158%	187%	178%	163%	168%	175%	174%	159%	141%	155%	145%	169%	179%	179%	184%	167.7%	209.3%	166%	176%
New Jersey Resources Corp	161%	186%	162%	178%	191%	229%	225%	224%	226%	224%	220%	245%	251%	275%	246%	222.6%	200.0%	201%	237%
NICOR Inc	179%	216%	195%	187%	220%	242%	260%	226%	227%	239%	199%	185%	210%	222%	234%	228.7%	200.0%	219%	211%
Northwest Natural Gas Co	162%	176%	161%	146%	156%	173%	169%	141%	129%	133%	145%	144%	153%	172%	177%	208.1%	201.0%	155%	171%
Piedmont Natural Gas Co	180%	214%	186%	182%	183%	217%	222%	213%	195%	199%	186%	211%	212%	208%	221%	209.9%	237.0%	199%	212%
South Jersey Industries	154%	175%	141%	142%	146%	178%	209%	202%	196%	205%	185%	170%	195%	221%	209%	231.2%	195.9%	175%	201%
Southwest Gas Corp	81%	100%	103%	103%	121%	129%	139%	147%	120%	127%	123%	118%	127%	135%	161%	149.4%	144.9%	117%	137%
WGL Holdings	173%	189%	165%	164%	178%	199%	197%	176%	177%	177%	152%	162%	175%	183%	168%	172.4%	146.0%	180%	166%
Average	159%	183%	165%	163%	180%	197%	202%	187%	175%	181%	168%	174%	183%	193%	193%	191%	179%	**179%**	**183%**
Median	161%	188%	167%	168%	181%	191%	203%	189%	173%	180%	162%	169%	182%	187%	185%	198%	198%	**180%**	**183%**

Source: Calculations made from data contained in Value Line Investment Survey.

STANDARD & POOR'S 500 COMPOSITE RETURNS AND MARKET-TO-BOOK RATIOS 1992 - 2007

YEAR	RETURN ON AVERAGE EQUITY	MARKET-TO BOOK RATIO
1992	12.2%	271%
1993	13.2%	272%
1994	16.4%	246%
1995	16.6%	264%
1996	17.1%	299%
1997	16.3%	354%
1998	14.6%	421%
1999	17.3%	481%
2000	16.2%	453%
2001	7.5%	353%
2002	8.4%	296%
2003	14.2%	278%
2004	15.0%	291%
2005	16.1%	278%
2006	17.0%	277%
2007	12.8%	284%
Averages:		
1992-2001	14.7%	341%
2002-2007	13.9%	284%

Source: Standard & Poor's Analyst's Handbook, 2008 edition, page 1.

RISK INDICATORS

GROUP	VALUE LINE SAFETY	VALUE LINE BETA	VALUE LINE FIN STR	S & P STK RANK
S & P's 500 Composite	2.7	1.05	B++	B
Parcell Proxy Group	2.6	0.72	B+	B
Grant Comparable Company Group	1.9	0.67	A-	A-

Sources: Value Line Investment Survey, Standard & Poor's Stock Guide.

Definitions:

Safety rankings are in a range of 1 to 5, with 1 representing the highest safety or lowest risk.

Beta reflects the variability of a particular stock, relative to the market as a whole. A stock with a beta of 1.0 moves in concert with the market, a stock with a beta below 1.0 is less variable than the market, and a stock with a beta above 1.0 is more variable than the market.

Financial strengths range from C to A++, with the latter representing the highest level.

Common stock rankings range from D to A+, with the later representing the highest level.

Exhibit___(DCP-1)
Schedule 13

UNS GAS INC
RATING AGENCY RATIOS

Item	Percent	Cost	Weighted Cost	Pre-Tax Cost	
Long-Term Debt	50.01%	6.49%	3.25%	3.25%	
Common Equity	49.99%	10.00%	5.00%	8.33%	
Total	100.00%		8.24%	11.58%	1/

1/ Post-tax weighted cost divided by .60 (composite tax factor)

Pre-Tax coverage = **3.57**
11.58% /3.25%

Standard & Poor's Utility Benchmark Ratios: Business Profile of "4"	A	BBB
Pre-tax coverage	3.3x - 4.0x	2.2x - 3.0x
Total debt to total capital	45%-52%	52%-62%

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	DOCKET NO. G-04204A-08-0571

(PUBLIC)

DIRECT

TESTIMONY

OF

RITA R. BEALE

ON BEHALF OF THE STAFF OF THE

ARIZONA CORPORATION COMMISSION

JUNE 08, 2009

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EXECUTIVE SUMMARY
UNS GAS, INC.
DOCKET NO. G-04204A-08-0571

In April and May 2009, I conducted a prudency review of the gas procurement operations of UNS Gas, Inc. My testimony focused on the period from January 2006 to June 2008, with nine findings and also ten recommendations for the Commissioners to consider. I reviewed the decision to terminate the BP Energy Services contract, the commodity and pipeline charges of the PGA Bank Balances, individual transactions, future pipeline planning, purchasing strategies and policies, and observed first-hand the Day Ahead gas purchasing, nominating and scheduling processes. My recommendations are:

(1) UNS Gas should conduct a thorough analysis of excess interstate pipeline capacity that could be currently optimized through Asset Management Arrangements (AMA).

(2) If excess pipeline capacity is available, UNS Gas should have Tucson Electric Power ("TEP"), seek potential counterparties on UNS Gas' behalf, at least annually, to optimize all of its excess capacity on both Transwestern and the El Paso Pipeline, although not at the expense of incurring a net increase in El Paso charges and penalties.

(3) UNS Gas should be required to supplement the information filed monthly to the Commission to tie out and support all entries of the Purchased Gas Adjustor Bank Balance, and specifically to include the *UNS Gas Core Market/ System Supply Imbalance Report* which finalizes tie-out of the commodity balances by pipeline.

(4) To ensure accuracy of the PGA filings, personnel from the Energy Settlements & Billing Department should receive additional training in the operating practices and terminology used by TEP Wholesale Department for gas procurement.

(5) The *UNS Gas Inc. Price Stabilization Policy* should be changed to require consideration of purchases during the three excluded months of August, September and October. Automatically excluding these months created missed opportunities to buy lower-priced gas during 2006, 2007 and 2008.

(6) To increase its hedge documentation, UNS Gas should create a record indicating the months that management decides to deviate from a ratable purchasing pattern,[1] even if it as simple as using a checklist denoting 'management decided not to hedge'.

(7) The *UNS Gas Inc. Price Stabilization Policy* should also be amended for any changes to gas purchasing strategy effective September 2008, when TEP took over gas procurement.

(8) The *UNS Gas Inc. Price Stabilization Policy* must be updated at least annually to reflect current practices and procedures.

(9) All parties involved with gas procurement should acknowledge the *UNS Gas Inc. Price Stabilization Policy* by signing annually, including Gas Scheduling, Transportation Contracts, Risk Management, and Risk Control; not just the traders.

---

[1] The *UNS Gas Inc. Price Stabilization Policy* essentially sets a non-discretionary portion of forecasted gas load (minimum 45 percent) to be hedged with fixed price instruments at ratable quantities of 1/27th over 27 different months leading up to the physical flow month, excluding August, September and October.

(10) A single person should be assigned as the 'policy owner' of the *UNS Gas Inc. Price Stabilization Policy* to ensure, on an annual basis, that the policy is accurate before it is approved by the Corporate Risk Management Committee.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Rita Regina Beale. I am a consultant employed with Energy Ventures Analysis, Inc. ("EVA"). My business address is 1901 N. Moore Street, Suite 1200, Arlington, Virginia 22209-1706.

Q. Please summarize your educational background and professional experience.

A. I am a graduate of Rider University and the Colorado School of Mines with a Bachelor of Science in Geology and Master of Science in Mineral Economics, from these respective institutions. I have about 22 years of varied energy commodity experience in oil, gas and electricity, with about eight years as an energy commodity analyst on Wall Street, mostly at Lehman Brothers and Goldman Sachs. I also spent about four years as a Senior Manager with Arthur Andersen in financial and commodity risk consulting. And I have been Vice President at two deregulated power companies, responsible for wholesale power supply and trading at Idaho Energy LP and First Choice Power LP in Texas. Currently I am a Principal with EVA.

Q. What are your duties and responsibilities at EVA?

A. I serve as a consultant and analyst at EVA. EVA is nationally known for its work in the energy and emission fields and engages in a variety of consulting projects for the private and public sector. I have worked on behalf of the Staff of the Arizona Corporation Commission in two prior rate cases, Dockets G-01551A-07-0504 and E-01933A-07-0402. In the energy area, much of our work is related to analysis of the electric power industry, fuel markets, and the transportation thereof. EVA's clients include fuel producers, electric and gas utilities, industrial energy consumers, transporters, and private investors in energy industries. Exhibit RB-1 presents my resume at the end of this testimony.

Q. What is the scope of your testimony in this case?

A. I am appearing on behalf of the Staff of the Arizona Corporation Commission-Utilities Division ("ACC") to address the prudency and reasonableness of the gas procurement practices of UNS Gas, Inc. ("UNS Gas") from January 2006 to June 2008. Also my testimony discusses operational and role changes for UNS Gas since September 2008.

SUMMARY OF TESTIMONY AND RECOMMENDATIONS

Q. Briefly summarize how your testimony is organized.

A. My gas procurement testimony is organized into seven sections. Section one discusses the reasons for the termination of BP Energy Services as UNS Gas' full requirements supplier and the transition to taking gas procurement in-house to Tucson Electric Power ("TEP") Wholesale Department.[2] Section two discusses planning for future UNS Gas pipeline capacity. Section three presents my audit of the Purchased Gas Adjustor Bank. In section four, I comment on UNS Gas purchasing strategies. Section five examines UNS Gas policies and procedures. The final two sections discuss an on-site visit to observe daily purchasing, nominating and scheduling and an audit of selected transactions. Exhibits RB-2 through RB-7 support my findings and recommendations.

Q. Please summarize your additional findings.

A. My findings are:

(1) No formal cost/benefit study was conducted by UNS Gas when deciding to discontinue the relationship with BP Energy Services as its full requirements supplier and to instead bring gas supply, nomination and scheduling operations into TEP Wholesale Department, as of September 2008. While some types of

[2] TEP and UniSource Energy Services are both subsidiaries of the publically traded entity, UniSource Energy Corporation, based in Tucson, Arizona. Under UniSource Energy Services, UNS Gas is the regulated gas utility that serves Arizona ratepayers with gas commodity and operates the physical system.

costs will increase during the short run, for instance associated TEP personnel costs, it was a rational decision and other important types of benefits are being realized by ratepayers that should continue long term.

(2) An audit of the PGA Bank Balance was conducted specifically for commodity and pipeline charges and credits. It reconciled the underlying charges and credits to within $9,834 of the filed PGA amount, compared to total charges of $240,522,666 for January 2006 to June 2008. Categories examined include (a) fixed price hedge transactions, (b) First of Month Index purchases, (c) Day Ahead purchases, (d) pipeline transportation charges, and (e) pipeline commodity balances that are carried forward, along with other items.

(3) Three primary strategies were used to purchase gas and found to generally balance price stability and supply reliability. However, one component of the fixed price hedge strategy is ineffective and should be revised per my recommendations.

(4) While company policies and procedures are generally reasonable, the UNS Gas Stabilization Policy 2009 is out of date, and no longer reflects all current procedures and practices.

(5) Purchase prices of natural gas commodity appeared reasonable relative to industry data, and the amount of pipeline capacity appeared prudent during the study period.

(6) A review of the analysis of normal peak day load and design day load requirements against pipeline capacity through 2011 found that current pipeline capacity contracts are likely to be sufficient for several additional years, possibly through 2013, although there is a lot of uncertainty about load growth given the recession and potential federal carbon legislation.

(7) Pipeline penalties and other charges, which are in addition to the typical demand and usage charges, were reasonable.

(8) An on-site visit to TEP Wholesale Department was made on April 14, 2009, to witness and analyze Day Ahead gas purchasing, nominating and scheduling processes. Purchases and practices were found to be reasonable, including bidder award.

(9) Six transactions were audited and found to be compliant with company policies and procedures.

Q. Please summarize your recommendations for the Commission to consider.

A. I have ten recommendations, in order of discussion within my testimony:

(1) UNS Gas should conduct a thorough analysis of excess interstate pipeline capacity that could be optimized through Asset Management Arrangements ("AMA").

(2) If excess pipeline capacity is available, UNS Gas should have TEP seek potential counterparties on UNS Gas' behalf, at least annually, to optimize all of its excess capacity on both Transwestern and also on El Paso Pipeline, although not at the expense of incurring a net increase in El Paso charges and penalties.

(3) UNS Gas should be required to supplement the information filed monthly to the Commission to tie out and support all entries of the Purchased Gas Adjustor Bank Balance, and to specifically include the UNSG Core Market/ System Supply Imbalance Report which finalizes tie-out of the commodity balances by pipeline.

(4) To ensure accuracy of the PGA filings, personnel from the Energy Settlements & Billing Department should receive additional training in the operating practices and terminology of TEP Wholesale Department for gas procurement.

(5) The UNS Gas Inc. Price Stabilization Policy should be changed to require consideration of purchases during the three excluded months of August, September and October. Automatically excluding these months created missed opportunities to buy lower-priced gas during 2006, 2007 and 2008.

(6) To increase its hedge documentation, UNS Gas should create a record indicating the months that management decides to deviate from a ratable purchasing pattern,[3] even if it as simple as using a checklist denoting 'management decided not to hedge'.

(7) The UNS Gas Inc. Price Stabilization Policy should also be amended for any strategy changes effective September 2008, when TEP took over gas procurement.

(8) The UNS Gas Inc. Price Stabilization Policy must be updated at least annually to reflect current practices and procedures before being approved by the Corporate Risk Management Committee.

(9) All parties involved with gas procurement should acknowledge the UNS Gas Inc. Price Stabilization Policy by signing annually, including Gas Scheduling, Transportation Contracts, Risk Management, and Risk Control, and not just the traders.

(10) A single person should be assigned as the 'policy owner' of the UNS Gas Inc. Price Stabilization Policy to ensure, on an annual basis, that the policy is accurate before it is approved by the Corporate Risk Management Committee.

GAS PROCUREMENT CHANGES FROM BP TO TEP WHOLESALE

Q. What was the relationship with BP Energy Services during the audit period?

A. BP Energy Services provided UNS Gas with natural gas supply at full requirements, and in return UNS Gas provided BP Energy with rights to optimize UNS Gas' interstate pipeline capacity. Any upside value was split equally by UNS Gas ratepayers and BP. The full requirements service allowed UNS Gas to take more gas (swing up), or send back excess gas (swing down), on a daily basis as load requirements dictated. Such swing

[3] The *UNS Gas Inc. Price Stabilization Policy* essentially sets a non-discretionary portion of forecasted gas load (minimum 45 percent) to be hedged with fixed price instruments at ratable quantities of 1/27th over 27 different months leading up to the physical flow month, excluding August, September and October.

transactions occurred at [redacted]. The agreement required UNS Gas to provide a daily forecast of its load to BP Energy.

Q. When did the relationship between the two parties change?

A. Contractually, gas procurement services ended with BP Energy Services on August 31, 2008 and began in TEP Wholesale Department starting September 1, 2008. As a result, BP's role changed to become one of a number of suppliers canvassed by UNS Gas to purchase gas.

Q. Why did the transition occur?

A. In 2006, El Paso Pipeline dramatically changed its rates and tariff structure, to require several types of no-notice and other services, which effectively prevented shippers from swinging quantities on a daily and intraday basis, unless shippers paid for the flexibility, also referred to as "optionality". When all of the optionality is monetized by a shipper, the assets are considered fully optimized. Subscription to the new swing services was expensive, and shippers were extremely likely to be caught by other charges and penalties if they did not buy a prescribed set of no-notice services. Under the new El Paso regime, entities serving full requirements loads, like UNS Gas, also found that to minimize additional charges and penalties, they needed to retain any excess hourly capacity to be rolled forward through the day for use by their own load to credit against future hours of higher than anticipated load. In such a different environment, it became difficult for BP to provide UNS Gas with the same daily swing services at the same low price.

Q. Why is optimization so important to ratepayers?

A. If the pipeline contracts are not used to serve the ratepayers' load, they become idle assets simply incurring expenses. Optimization presents an opportunity to recover some of those expenses.

Q. What was the value of the pipeline optimization component?

A. During the study period, UNS Gas ratepayers benefited by [redacted] by their 50 percent share, although the final month of any optimization whatsoever was November 2007, and only $12,931 was paid to UNS Gas during the final twenty out of thirty months examined.

Q. What was BP Energy's final offer to retain the UNS Gas account?

A. In July 2008 and in view of the natural cessation of El Paso pipeline optimization, BP's offer was contingent on collection of a monthly scheduling and nomination service charge of [redacted].

Q. Was UNS Gas able to find a better partner?

A. Yes, for pipeline optimization. As of March 2009, the new capacity on the Transwestern Phoenix Lateral was not required to serve ratepayer load, although UNS Gas must pay pipeline demand charges to hold the capacity in reserve. Subsequently for March 2009, this new capacity was released in an AMA to Tenaska Marketing Ventures (TMV). Ratepayers have benefitted from a better sharing arrangement of [redacted]. For March 2009, the difference between [redacted], in favor of ratepayers, *ceteris paribus*, to offset the otherwise idle pipeline capacity.

Q. Are there any other benefits that derive to UNS Gas ratepayers?

A. UNS Gas has gained the benefit of first hand price discovery by virtue of TEP's direct participation in the market, whereas formerly BP was the entity facing the market. UNS Gas also retains the choice of changing AMA partners should market conditions warrant, both of which should help lower the gas supply and transport costs over the long term. There should be increased accountability for decision-making during severe and critical pipeline operating conditions. Sharing of the cost of gas procurement operations with two UniSource entities, Tucson Electric and UNS Electric is another benefit. UNS Gas's load is winter peaking versus summer peaking for the electric companies, so they are a natural complement. Other benefits are related to credit risk management which is essential to lock-in purchases of gas in the forward markets. UNS Gas's counterparty credit risk is theoretically more diversified by using multiple gas suppliers, and UNS Gas should be able to access a greater amount of credit by using multiple suppliers.

Q. What are the O&M costs of gas procurement for UNS Gas?

A. Based on UniSource internal documentation, UNS Gas's O&M for gas procurement had average quarterly increases of 7.3 percent for the four quarters through 1Q2009, as a result of all items, including changes in gas procurement personnel. If the 1Q2009 increase over 1Q2008 is annualized, it equals $60,571.

FUTURE PIPELINE CAPACITY PLANNING

Q. Did you review UNS Gas's planning for future pipeline capacity needs, and if so, what were your findings?

A. Yes, I reviewed the interstate contract quantities against normal peak day load and design day load requirements through 2011. Given the recession and potential federal legislation regulating carbon, prior load growth estimates may be too high. I recommend that UNS Gas conduct a new analysis of excess interstate pipeline capacity that could be optimized through Asset Management Arrangements ("AMA").

Q. Were there any changes to the pipeline portfolio?

A. Yes. The most significant change resulted from the changes in the new El Paso rates and tariff on January 1, 2006. The most recent change is that UNS Gas expanded its total pipeline capacity by committing to the new Phoenix Lateral effective March 1, 2009. UNS Gas sought and was granted Commission pre-approval for acquisition and cost recovery of this new capacity in Docket G-04204A-0627, Decision No. 69333, partly to ensure diversification of gas supplies into the region and also away from the traditional monopoly held by El Paso Pipeline.

Q. For how long will the current pipeline capacity be sufficient?

A. Mr. David Hutchens, Vice President of Wholesale Energy and UNS Gas, believes the current portfolio may be sufficient through 2013. In all parts of the United States, there is great uncertainty about the amount of future load growth, given the current recession and potential federal legislation regulating carbon.

Q. Are you satisfied that all pipeline optionality is being monetized?

A. There is currently quite a bit of excess pipeline capacity, and because UNS Gas's load has declined due to recession, there may additional excess capacity that was not previously available. I recommend that after UNS Gas conducts a new analysis of excess pipeline capacity, that UNS Gas have TEP seek potential counterparties on behalf of UNS Gas, at least annually, to optimize all of the excess capacity on both Transwestern and also on El Paso Pipeline, although not at the expense of incurring a net increase in El Paso charges and penalties.

PURCHASED GAS ADJUSTOR BANK

Q. Did you review the PGA accounting?

A. Yes. I focused on validating the commodity and transportation expenses of the PGA Bank Balance Statement (primarily Exhibit A, lines 2 and 3) for the 30-month study period.

Q. What was your approach?

A. To the extent practical, I examined all available underlying transaction data from the system of record and compared it to PGA filings. Because BP was the full requirements supplier, First of Month and Day Ahead purchases are not contained in the system of record, and instead have been aggregated on internal spreadsheets. I also examined all the pipeline charges that were aggregated on internal spreadsheets.

Q. What were your findings?

A. For the 30-month study period, I reconciled the underlying charges and credits to within $9,834 of the filed PGA amount. Total costs filed to be recovered were $240,522,666, per Exhibit A, line 6.

Q. Why couldn't you reconcile to the penny?

A. The true-up process is fairly complex, and it was difficult to reconcile all of the charges without better documentation support. I strongly recommend that UNS Gas be required to tie out and supplement that information to the Commission each month with the filed PGA reports. Past testimony by Staff witness George Wennerlyn in February 9, 2007 (Docket G-04204A-06-0463, G-04204A-06-0413, G-04204A-06-0831) supported a similar finding and recommendation. I also specifically recommend that the Commission to require that the *Core Market/System Supply Imbalance Report* be added to the required documentation support for filing.

Q. What is in the *Core Market/System Supply Imbalance Report*?

A. The core market commodity imbalance is entered on Exhibit B, line 26, of the monthly filed PGA reports. This internal UNS Gas report supports it and attempts to reconcile all of the mismatches between scheduled and actual volumes and the final charges to the core ratepayers. Each month, pipeline imbalances can be cashed-out in the current month, carried forward into the next month, or resolved by additional transactions with a third party. During the study period, the core market commodity imbalance totaled a net credit of $380,045 to ratepayers, but experienced monthly swings from a credit of $694,132 to a debit of $805,657. To ensure these swings are not imprudent, their genesis and resolution need to be tracked easily.

Q. Do you have any other recommendations to share on the PGA?

A. Yes. Since January 2009, the Energy Settlements & Billing Department took internal responsibility to prepare the PGA reports, with final oversight responsibility designated to a single person in TEP. To ensure accuracy of the PGA filings, I recommend that personnel from the Energy Settlements & Billing Department receive additional training in the operating practices and terminology of gas procurement in TEP Wholesale.

Q. What led you to this conclusion?

A. I received errant data in response to formal data request RB 4.1, compiled by Energy Settlements & Billing Department. I believe the errors were not intentional, but due to a lack of understanding about some of the details of wholesale gas procurement, as the Analyst had not been working with the data for very long. There are number of complex processes that require considerable experience to be completely familiar with terminology unique to gas procurement.

GAS PURCHASING STRATEGIES

Q. What were the UNS Gas purchasing strategies?

A. UNS Gas used three primary strategies to purchase gas: fixed price hedges, First of the Month Index and Day Ahead Index, supplemented by two lesser strategies: Intraday purchases and the carry forward of pipeline imbalances. Exhibit RB-2 shows the monthly percentage of the volume of gas purchased by each primary strategy. By dollar value during the study period, $113,948,609 of gas was purchased with fixed price hedges, $32,289,078 of gas was purchased at First of the Month Index, and $66,781,956 of gas was purchased at Day Ahead Index. These values are before adjustments due to core market commodity imbalance, T-1[4] imbalances, NSP[5] margins, and financial hedges.

Exhibit RB-2

Primary Purchasing Strategies for Scheduled Delivery Volumes

	Hedge Quantity	FOM Quantity	Daily Quantity	Delivered Core Purchases
Jan-06	65%	17%	18%	100%
Feb-06	55%	34%	11%	100%
Mar-06	42%	12%	46%	100%
Apr-06	58%	14%	28%	100%
May-06	68%	22%	9%	100%
Jun-06	47%	24%	29%	100%
Jul-06	49%	29%	22%	100%
Aug-06	46%	29%	25%	100%
Sep-06	42%	21%	37%	100%
Oct-06	38%	9%	53%	100%
Nov-06	50%	26%	24%	100%
Dec-06	47%	17%	37%	100%
Jan-07	47%	9%	44%	100%
Feb-07	47%	18%	35%	100%
Mar-07	55%	13%	31%	100%
Apr-07	57%	7%	36%	100%
May-07	66%	8%	26%	100%
Jun-07	62%	22%	16%	100%
Jul-07	50%	28%	22%	100%
Aug-07	49%	27%	24%	100%
Sep-07	59%	24%	17%	100%
Oct-07	50%	11%	38%	100%
Nov-07	66%	27%	8%	100%
Dec-07	51%	14%	34%	100%
Jan-08	56%	6%	38%	100%
Feb-08	50%	12%	38%	100%
Mar-08	57%	9%	34%	100%
Apr-08	55%	12%	33%	100%
May-08	45%	15%	40%	100%
Jun-08	42%	24%	35%	100%

[4] "T-1" refers to the Pricing Plan T-1, Transportation of Customer-Secured Natural Gas, such that a customer procures its own gas to the UNS Gas city gate and UNS transports the gas thereafter to the customer's downstream facility.

[5] "NSP" is Pricing Plan NSP-1, the Negotiated Sales Program, such that a customer has negotiated with UNS Gas for the delivery of natural gas commodity.

Q. Can you describe the fixed price strategy?

A. It is documented in the *UNS Gas Inc. Price Stabilization Policy.* For fixed price purchases, UNS Gas is required to lock the price of gas to reach a minimum of 45 percent of the forecasted load by two months prior to physical flow. There is no discrimination between physical and financial instruments, although UNS Gas has traditionally chosen to execute primarily physical instruments. The policy recommends that the 45 percent be spread out over three years in about 27 separate monthly transactions to accomplish effective dollar cost averaging. Also, purchases are required to be excluded during the three months of August, September and October due to potentially high hurricane activity.

Q. Do you think the fixed price strategy is prudent?

A. Generally, I think it is reasonable. My primary criticism is that I believe the concept of automatically eliminating August through October from the purchase schedule is inherently flawed, since those months can give rise to both lower and higher prices.

Q. Please provide some illustrations of this phenomenon for the excluded months?

A. During the past three years of 2006, 2007 and 2008, the excluded months were not necessarily high priced periods, relative to the other nine months of the year. Settlement of the NYMEX Henry Hub futures contract, which is a core component in setting the fixed price at San Juan for any transaction, reached some of its lowest values of the year during the excluded months. Exhibits RB-3 and RB-4 provide examples during the lifetime of two NYMEX Henry Hub futures contracts, the December 2007 and December 2009 contracts, respectively. Simple observation of the graphs indicates that the excluded periods were often lower than the other nine months of the year in 2006, 2007 and 2008.

Exhibit RB-3

History of December 2007 NYMEX Henry Hub Futures Contract

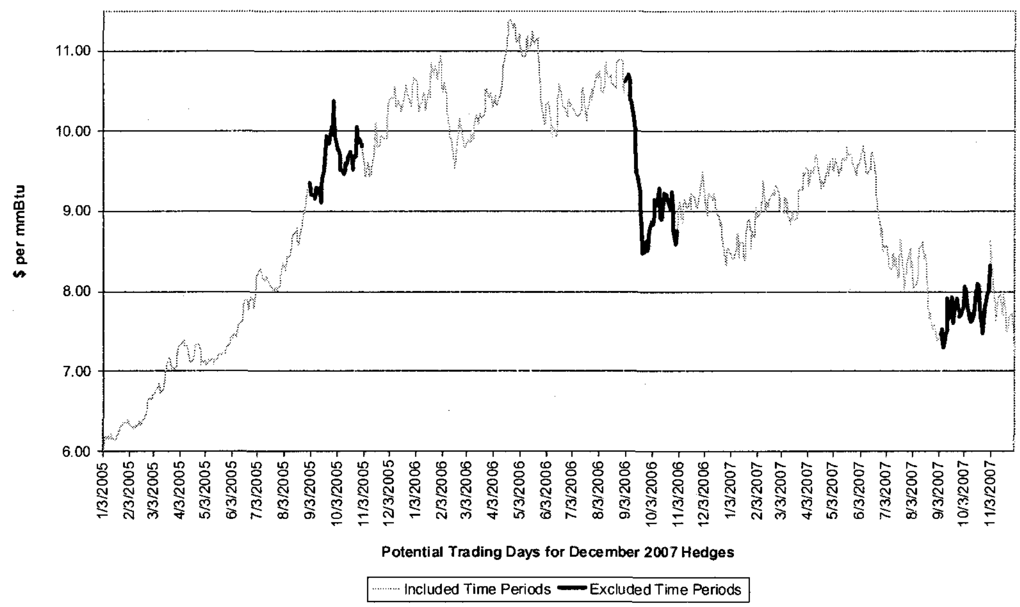
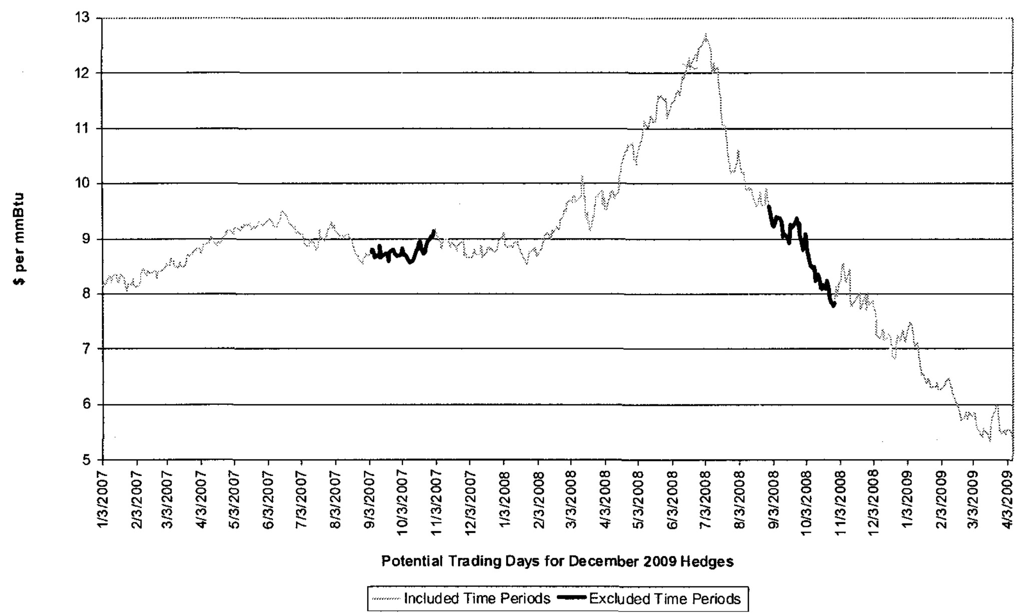


Exhibit RB-4

History of December 2009 NYMEX Henry Hub Futures Contract



Q. What else makes you think the strategy is flawed?

A. The United States is currently in a period of generally weak gas prices, so it would be prudent to take advantage of this weakness through fixed price hedges. As a point of reference, the *Inside FERC* First of Month Index for May 2009 gas delivered to El Paso San Juan settled at only $2.50 mmBtu. In my opinion, there is more risk that gas prices will rise after 2009 than decline, so automatically eliminating purchases during August 2009, September 2009 and October 2009 may not be prudent. There could be good buying opportunities for the 36-month strip, which is the focus of UNS Gas' hedging program.

Q. What are the dynamics that might keep prices low during 2009?

A. There is a strong likelihood that U.S. working gas storage will reach full capacity ahead of the traditional November 1st date, which would tend to strand excess gas on the pipeline system keeping prices in a weakened state. Storage is expected to reach full capacity early this year because on average U.S. natural gas production is still rising versus 2008, but U.S. consumption has not yet bottomed versus 2008.

Q. Do you recommend that the *UNS Gas Inc. Price Stabilization Policy* be amended, and if so, how?

A. Yes, I recommend that the policy be changed to require consideration of purchases during the three excluded months, since automatically excluding them created missed opportunities to purchase lower priced gas in 2006, 2007 and 2008. Also, I recommend that the policy be amended for any strategy changes effective September 2008, when TEP took over gas procurement.

Q. Should the policy be changed every year?

A. Not necessarily, although it is Best Practice for a management team to examine the performance of its hedging policy after-the-fact to determine where the policy succeeded and where it failed. The *UNS Gas Inc. Price Stabilization Policy* has had virtually no changes during the past four versions that I reviewed. In the last UNS Gas rate case, Docket No. G-04204A-06-0463, staff witness Mr. Jerry Mendl warned of such a potential risk, "approval of the (2006 Gas Price Stabilization) policy would create a safe harbor that would increase the resistance of UNS Gas to change polices when conditions warranted". The requirement to exclude August, September and October may have appeared reasonable during 2005, but does not appear reasonable during 2006, 2007 and 2008.

Q. Do you recommend that any of their gas purchases be deemed not prudent for these reasons?

A. No. No one can have perfect foresight, and that is why the policy must be reviewed in hindsight to determine its effectiveness. Also, there is a learning curve associated with any new policy. UNS Gas' ability to apply its discretion and judgment during the hedging process is allowed by the policy, and it should be retained due to rapidly changing natural gas markets. This makes hedge documentation more onerous, an area where TEP performs poorly.

Q. Did UNS Gas adhere to its fixed price strategy?

A. Exhibit RB-5 shows that UNS Gas met the 45 percent target each month. It also measures the final quantities hedged against several vintages of load forecasts, which are issued annually by UniSource Financial Forecasting Department. The changes illustrate the volatility of the load forecast going back in time, because the same final hedge quantities are compared against load forecasts of prior years.

Exhibit RB-5

Percent of UNSG Load Hedged Forward				
	By Vintage of Load Forecast			
Delivery Month	2005	2006	2007	2008
Jan-06	60%	70%		
Feb-06	56%	56%		
Mar-06	53%	57%		
Apr-06	48%	48%		
May-06	53%	57%		
Jun-06	50%	53%		
Jul-06	49%	54%		
Aug-06	47%	48%		
Sep-06	48%	51%		
Oct-06	48%	45%		
Nov-06	50%	49%		
Dec-06	57%	48%		
Jan-07	51%	59%	61%	
Feb-07	48%	48%	50%	
Mar-07	49%	52%	51%	
Apr-07	53%	53%	57%	
May-07	49%	52%	56%	
Jun-07	53%	56%	67%	
Jul-07	51%	56%	54%	
Aug-07	46%	47%	48%	
Sep-07	53%	56%	60%	
Oct-07	53%	50%	52%	
Nov-07	55%	54%	50%	
Dec-07	63%	52%	55%	
Jan-08	58%	67%	70%	69%
Feb-08	57%	56%	60%	59%
Mar-08	55%	59%	57%	56%
Apr-08	46%	45%	50%	56%
May-08	43%	46%	49%	55%
Jun-08	43%	45%	55%	52%

Q. Did UNS Gas adhere to discipline of making 27 purchases for each month?

A. Exhibit RB-6 shows that the discipline of making 27 monthly purchases for each month was not perfectly executed. The low numbers in the beginning of the study period are affected by a prior policy that required a fewer number of trades, then the policy increased the recommended number of trades. The transaction data underlying Exhibit RB-6 show a lack of perfect discipline. For instance, during November 2005, hedges were not executed for months beyond March 2006. No hedges were executed during December 2005. Then

27 transactions were executed during January 2006. A fixed price hedge was last executed for the flow month of June 2008 during December 2007. There are other examples of imprecise execution of the strategy.

Exhibit RB-6

	Number of Physical & Financial Hedge Transactions
Jan-06	7
Feb-06	6
Mar-06	6
Apr-06	6
May-06	8
Jun-06	8
Jul-06	11
Aug-06	12
Sep-06	13
Oct-06	13
Nov-06	14
Dec-06	14
Jan-07	14
Feb-07	13
Mar-07	15
Apr-07	13
May-07	15
Jun-07	15
Jul-07	18
Aug-07	19
Sep-07	21
Oct-07	13
Nov-07	13
Dec-07	21
Jan-08	22
Feb-08	21
Mar-08	21
Apr-08	19
May-08	19
Jun-08	19

Q. Does this concern you?

A. No, there is increasing adherence to the concept of executing 27 transactions for each month, which is acceptable. I did not query management on the exact reasons for each of the deviations from the frequency recommended by the policy for several reasons.

Changes to company-issued annual load forecasts can cause management to change the buying pattern. Management retains a discretionary component to the purchasing strategy, which appears to be surfacing in the purchasing patterns. The deviations from an expected 27 transactions seem to also show the difficulty of hedging mechanically without judgment, when management is allowed discretion in the policy.

Q. Are the deviations documented?

A. No, and I recommend to increase its hedge documentation, UNS Gas should create a record indicating the months that management decides to deviate from a ratable purchasing pattern, even if it as simple as using a checklist denoting 'management decided not to hedge'. My general experience has been that parties often have reluctance to record the exact reasons for each deviation, lest the often complex events associated with each determination be examined in hindsight under the microscope. Of course, the hedged transactions serve as proof of management's decisions about when to execute the ratable purchase policy.

Q. What are the second and third legs of the UNS Gas purchasing strategy?

A. As verbally described by the Portfolio Manager of gas purchasing, Mr. Ray Robey, the second and third legs of the purchase strategy involved buying the remainder, not already covered by hedges, roughly split between First of Month Index and Day Ahead Index. For instance, if forward hedges covered 45 percent, about 27.5 percent would be FOM and about 27.5 percent would be Day Ahead. It should be noted that the UNS Gas strategy appears to have changed somewhat after TEP took over gas procurement, starting September 2008.

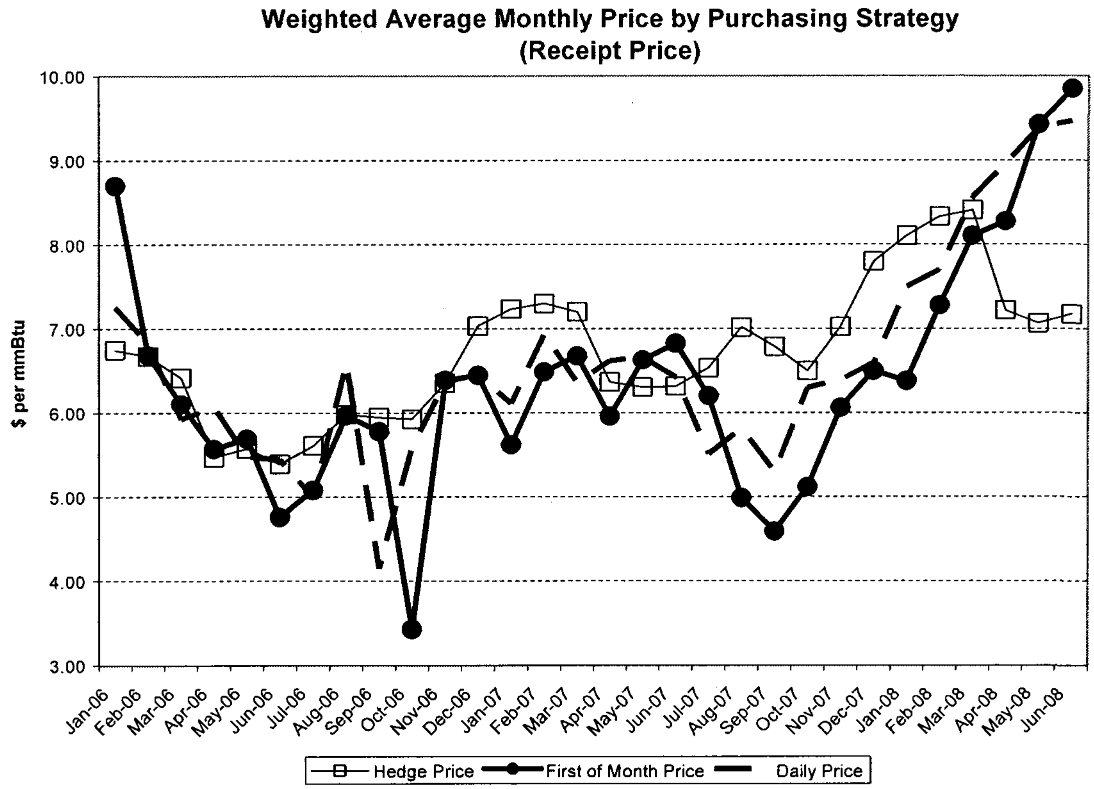
Q. Why not purchase all of the remainder in the FOM market?

A. Because weather, and therefore load, is impossible to predict with complete accuracy, it is prudent to take account of a potentially better and more real time weather forecast in the load estimate, before determining the final amount of gas to purchase.

Q. Were the resultant purchase prices reasonable?

A. Yes, all prices appear reasonable. Because UNS Gas purchased gas from BP at FOM Index and GDD Index, index prices are reasonable. These prices were checked independently for accuracy with the published indexes. Analyzing the reasonableness of the average hedge price is based on hedge strategy actually employed, as discussed earlier. Receipt prices paid by UNS Gas are shown in Exhibit RB-7 for the three primary purchasing strategies. Hedge prices are weighted by volume.

Exhibit RB-7



Q. Were the pipeline charges reasonable?

A. Yes. I reviewed all pipeline charges incurred by UNS Gas during the study period including demand, usage, and all the other types of charges including penalties. The additional pipeline charges beyond demand and usage paid to El Paso Pipeline appear reasonable, and somewhat unavoidable, given the newness and difficult to implement standards of the El Paso Pipeline tariff effective beginning January 1, 2006, and the uncontrollable weather events occurring in November 2006. The general nature of the new tariff attempts to remove all optionality from the shipper, unless the optionality is subscribed to and paid for. El Paso subsequently revised many of the difficult to implement operating requirements, that began on January 1, 2006, sometimes by order of the FERC and after complaints from the shippers. Also by order of the FERC, El Paso refunded $219,645 of charges and penalties incurred by UNS Gas from August 2006 to September 2007.

Q. What were the amounts of pipeline charges paid by each category?

A. UNS Gas paid a gross total of $30,222,222 million, with $29,123,375 of pipeline charges flowing through to the PGA before credits and debits with NSP and T-1 customers and after El Paso refunds.[6] Gross El Paso charges included $22,009,443 in demand charges, $663,499 in usage charges, and $461,569 of other charges for scheduling penalties (7 percent), OPAS Violations (12 percent), Daily Imbalance Charges During Critical Periods (16 percent), Unauthorized Overrun (zero), Daily Variance (3 percent), and Balancing Cash Out (49 percent), after refunds and before NSP and T-1 credits. Gross Transwestern charges included $6,592,643 in demand charges and $168,524 in usage charges.

UNS GAS POLICIES AND PROCEDURES

Q. Which company policies and procedures did you review?

A. My review included annual copies for multiple years of the *UniSource Energy Corporation Energy Risk Control Policies Manual* and the *UNS Gas, Inc. Price Stabilization Policy*. I reviewed the PGA financial accounting policy, Energy Settlement PGA Bank Procedures, and the *UniSource Energy Corporation Code of Ethics and Principles of Business Conduct.*

Q. Do you have any other recommended changes to policies and procedures?

A. Yes, I have several, in addition to the ones previously discussed.

[6] NSP and T-1 debits and credits are deducted from gross pipeline charges, not flowing through to the PGA.

Q. What are they and the rationales behind them?

A. I recommend that the policies and procedures be updated at least annually to reflect current practices and procedures. A number of discrepancies were noted between the *UNS Gas Price Stabilization Policy* and trading room practices. I provided a list of discrepancies to TEP management. While current practices may be reasonable, the policy should always match practices. This is important to ensure the proper checks and balances are in place and are being adhered to. The discrepancies appear related to the fact that the *UNS Gas Inc. Price Stabilization Policy* virtually did not change for a number of years, even though operating practices evolved somewhat over the same time. Also, I recommend that all parties involved with gas procurement should acknowledge the policy by signing annually, including Gas Scheduling, Transportation Contracts, Risk Management, and Risk Control, not just the traders. This will help ensure that the roles of all parties are accurately reflected. Finally, I recommend that a single person be designated as the 'policy owner' to ensure, on an annual basis, that the policy is accurate before it is approved by the Corporate Risk Management Committee. A commercial person that is familiar with all aspects of gas procurement would be best.

ONSITE VISIT

Q. Did you make an on-site visit as requested?

A. Yes. I made an on-site visit to TEP Wholesale Department for three days on April 13-15, 2009 to interview personnel and gather additional information. My interviews included TEP personnel and management, and personnel from some corporate departments of UniSource, including Risk Control, Financial Forecasting, Internal Audit, and Energy Settlements. On April 14, 2009, I personally witnessed Day Ahead gas purchasing, nominating and scheduling processes. I found their practices to be effective and prudent, including bidder award. The next day gas purchasing decisions are made and executed by a single individual, the Portfolio Manager of natural gas for TEP, UNS Gas and UNS Electric, Mr. Ray Robey.

Q. How does Mr. Robey make the decision about which supplier to purchase from?

A. UNS Gas has master ISDA agreements with [redacted] gas suppliers, with [redacted] others in the administrative queue to be finalized, and NAESB agreements with [redacted] additional entities, with [redacted] more in the queue. To purchase Day Ahead gas, Mr. Robey canvasses the market for the best offers through an electronic trading house (Intercontinental Exchange), instant messaging, telephone, and a voice box that connects directly to a broker. However, he can only execute with those suppliers for which there are pre-existing master agreements and credit arrangements. This is one of the reasons why it's important for a company to maintain a good credit rating and to diversify its supplier base, in order to lift the best available offer prices.

Q. How does Mr. Robey make the decision about how much gas to purchase?

A. He generally consults the most recent load forecast and also considers any potential error in the load forecast of recent days which might contribute to the pipeline imbalance and attempts to keep a zero or low imbalance.

TRANSACTION AUDIT

Q. Did you audit any transactions for adherence to policies and procedures?

A. Yes. Six transactions were specifically reviewed for compliance with policies and procedures and found to be compliant. Two contracts were selected from each year in 2006, 2007 and 2008, including the bids related to gas supply for the 2008/2009 winter season where BP Energy Services won the right to supply the majority of the gas.

Q. Does this conclude your direct testimony?

A. Yes, it does.

RITA R. BEALE

EDUCATIONAL BACKGROUND

Master of Science	Mineral Economics, Colorado School of Mines, 1987
Bachelor of Science	Geology, Rider University, 1984 (Phi Beta Kappa Honor Key)

PROFESSIONAL EXPERIENCE

Current Position

ENERGY VENTURES ANALYSIS, INC. – Arlington, VA

Principal
Ms. Beale joined EVA in 2007 as co-head of the oil and natural gas practice, with additional specialization in electricity.

Prior Experience

WEST HILL GROUP - Aledo, TX **2005 - 2007**

Principal
- Analyzed investment costs of new NGL processing plant of ~$100 million and evaluated whether to use gas compressors or electric motors.
- Negotiated ERCOT power supply contract and structured heat rate terms to meet client's risk management objectives.
- Provided hedge strategy consultation and market timing to end-users.

FIRST CHOICE POWER LP - Fort Worth, TX **2003 - 2005**

Vice President, Energy Services
Executive officer with P&L responsibility for physical ERCOT power and financial natural gas. General management & leadership of five areas: (a) wholesale supply and portfolio management (b) customer deal pricing (c) back office settlement of wholesale supply contracts and preparation of General Ledger accounting entries (d) electric load forecasting for >200,000 customers (e) ERCOT market operations/protocols. Served on Risk Management Committee & Sarbanes Oxley Disclosure Committee.
- Working closely with C-level management, turned company around from negative commodity position. Stayed through successful sale of company.

- Acted as de-facto Director of Portfolio managing all commodity & operational risk of energy, ancillaries, and renewable energy as fixed price, basis, and option positions. Led multi-discipline team that structured & negotiated $800 million in power supply deals that enabled FCP to survive and restart customer acquisition.
- Help set up Special Purpose Entity (bankruptcy remote) to enhance company creditworthiness and serve as collateral for power supply contracts. Administered front office policies and practices to ensure adherence to risk policies and other contractual covenants.
- Managed staff of 22 with operating budget of ~$2 million. Responsible for annual and quarterly department forecasts and updates.

IDACORP ENERGY LP – Boise, ID **2002 - 2003**

Vice President & General Manager, Electric Power

P&L responsibility for physical & financial wholesale power trading, origination, and market analysis reporting to the President.

- Responsible for portfolio management of wholesale power book and exposures in fixed price, basis, index, and option positions in the western USA. Ensured trading compliance with all portfolio VaR limits and risk policies.
- Positions included deal flow from large commercial & industrial customers and a large number of power transmission contracts modeled as options.
- Activities included portfolio (re) valuation and resolution of regulatory & legal contractual issues.
- Led external sale of commodity book through bid process. Locked mark-to-market value to flatten book prior to sale. Reduced department by half to staff of 20 to meet BOD obligations until sale of book.

ANDERSEN LLP – Chicago, IL **1998 - 2002**

Senior Manager, Financial & Commodity Risk Consulting

Scoped, priced, and executed engagements as project manager. Fostered relationships with clients to spearhead key initiatives including business strategy, process reengineering and Sarbanes Oxley controls, risk management, and financial valuation.

- Responsibilities included developing and executing business plans, hiring and developing consulting personnel, quality assurance, and client satisfaction.

EL PASO ENERGY MARKETING – Houston, TX **1996 - 1998**

Manager, Natural Gas Storage Trading

P&L responsibility for financial & physical optimization of natural gas withdrawals and injections based on embedded optionality. Portfolio included proprietary leases and client asset management on 18 different pipelines in the East, US Gulf, Texas, Midwest, & Canada.

- Established new storage department from inception into operation.
- Developed & implemented rigorous market-based arbitrage pricing tools to determine schedules and extract maximum value in daily & forward markets.

<u>Manager, Structured Transactions</u>
Set-up initial structure desk and related processes to value & price complex physical natural gas transactions that included energy, storage, and pipeline capacity.

- Administered centralized pricing & execution for sales reps at six remote locations.
- Marketed OTC derivatives to personal book of customers.

ENERGY COMMODITY ANALYST
GOLDMAN, SACHS & CO - New York, NY **1993 - 1995**
LEHMAN BROTHERS - New York, NY **1988 - 1993**

For oil and natural gas, conducted fundamental research on global supply, demand, storage, and relevant trends impacting prices. Published price forecasts and trading recommendations for hedgers and specs. Produced research reports, led client teleconference calls, spoke at client conferences, and attended OPEC meetings as industry observer.

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. G-04204A-08-0571

DIRECT

TESTIMONY

OF

CORKY HANSON

ASSISTANT SUPERVISOR

SAFETY DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 08, 2009

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ATTACHMENTS

CORKY HANSON RESUME .... ATTACHMENT 1

EXECUTIVE SUMMARY
UNS GAS, INC.
DOCKET NO. G-04204A-08-0571

Mr. Hanson's Direct Testimony addresses the UNS Gas, Inc. list of capital improvements and new construction to determine whether the projects were used and are useful.

INTRODUCTION

Q. Please state your name and business address.

A. My name is Corky Hanson. My business address is 2200 N. Central Avenue, Phoenix.

Q. What is your current position and how long have you been employed by the Arizona Corporation Commission?

A. I am the Assistant Supervisor of the Pipeline Safety Section; I have been employed by the Arizona Corporation Commission ("Commission") for over 17 years.

Q. Please describe briefly your duties as a Assistant Supervisor.

A. As Assistant Supervisor, I am responsible for the following:

- Assist Supervisor in the management of the pipeline safety program.
- Review inspectors' reports for accuracy and completeness.
- Under the direction of the Supervisor, schedule activities and tasks and assign personnel to accomplish these projects.
- Assist Supervisor in development and updating of pipeline safety policies and procedures.
- Assume the role of Interim Supervisor in the absence of the Supervisor.

Q. Have you previously testified?

A. Yes, I have previously testified on behalf of the Commission in seven cases.

Q. What is the purpose of your testimony in these proceedings?

A. The purpose of my testimony is to address the UNS Gas, Inc. list of capital improvements and new construction to determine whether the projects were used and are useful.

ANALYSIS

Q. Does the Pipeline Safety Section have any concerns regarding the used and useful analysis of the list that would affect this rate case?

A. No.

Q. How were you able to determine the used and usefulness of the list?

A. I reviewed UNS Gas, Inc.'s response to Staff's 3rd set of data requests dated March 27, 2009. This data has a list of each project with a date and a map that identify the purpose of each project. Also, Gary Smith V.P. and General Manager of Gas Operation for UNS Gas, Inc. left me with his cell phone number to call him if I had any questions during the process. I took advantage of this opportunity on several occasions.

Q. Were there any non-compliance items noted during the 2009 comprehensive audit?

A. No.

Q. Does this conclude your Direct Testimony?

A. Yes, it does.

CORKY HANSON

- Prior to working for the Office of Pipeline Safety (OPS), Corky was the Operation Supervisor at Black Mountain Gas Company (BMG) for thirteen years. He was responsible for designing and engineering new pipeline systems, repair of existing pipelines, operation, maintenance and emergency response. At BMG, Corky had pipeline industry training in leak survey, cathodic protection, pressure regulation/relief devices, odorization, valve maintenance, construction of a pipeline and emergency response. Corky authored the original "Operation, Maintenance and Emergency Manual" for BMG.

- His other experience includes four years as a contractor employee doing construction for the local gas and water utility companies; two years in the U S Army (Combat Engineers).

- Corky has worked for OPS since May 4, 1992 where he has conducted numerous pipeline safety audits on both intrastate and interstate pipeline operators and incident investigations. Corky was a member of the Federal/State Operator Qualification Committee and The American Society of Mechanical Engineers (B31Q) Committee in developing a standard for qualification of pipeline personnel. He is also a current member of the Common Ground Alliance, a nonprofit organization dedicated to promoting effective damage prevention practices for underground utilities. Corky has been connected with the pipeline industry since 1974. On March 9, 2009 Corky was promoted to Pipeline Safety Assistant Supervisor.

- **Federal Training Courses:**

  Gas Pressure Regulation and Overpressure Protection Course
  Safety Evaluation of Pipeline Corrosion Control Systems I
  Safety Evaluation of Gas Pipeline Systems
  Pipeline Failure Investigation Techniques
  Pipeline Safety Regulation Application and Compliance Procedures
  Joining of Pipeline Materials
  Safety Evaluation of Pipeline Corrosion Control Systems II
  Safety Evaluation of Hazardous Liquid Pipeline Systems
  Liquefied Natural Gas Safety Technology and Inspection
  Operator Qualification
  Pipeline Reliability Assessment
  Integrity Management Courses
  General Pipeline Safety Awareness Course (Hazwoper)

ARIZONA CORPORATION COMMISSION – Office of Pipeline Safety

- New Employee Training (6 weeks)
- Master Meter Training Class
- Liquefied Petroleum Gas
- Welding Procedures and Visual Examination of Welds
- Incident Investigations
- Computer Science Classes

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA	)))))))))	DOCKET NO. G-04204A-08-0571

DIRECT

TESTIMONY

OF

JUAN C. MANRIQUE

PUBLIC UTILITIES ANALYST V

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 08, 2009

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EXECUTIVE SUMMARY
UNS GAS, INC.
DOCKET NO. G-04204A-08-0571

On November 7, 2008, UNS Gas, Inc. filed and application with the Commission for rate relief. The purpose of this testimony by Staff witness Juan C. Manrique is to present Staff's position on proposed changes to by the Company to its Rules and Regulations. Staff concludes that the changes proposed by UNS Gas, Inc. are prudent and recommends that they be authorized.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Juan Manrique. I am a Public Utilities Analyst employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as a Public Utilities Analyst.

A. In my capacity as a Public Utilities Analyst, I provide recommendations to the Commission on financings and certificates of convenience and necessity. I also perform studies to estimate the cost of capital for utilities that are seeking rate relief.

Q. Please describe your educational background and professional experience.

A. In 2005, I graduated from Arizona State University, receiving a Bachelor of Science degree in Finance. My course of studies included classes in corporate and international finance, investments, accounting, statistics, and economics. I began employment as a Staff Public Utilities Analyst in October 2008.

Q. What is the scope of your testimony in this case?

A. I will address the Rules and Regulations to be recommended for UNS Gas, Inc. ("UNS" or "Company").

ESTABLISHMENT OF SERVICE

Q. Has UNS revised its Establishment of Service Rules and Regulations as part of the current rate case?

A. Yes. UNS added language to its Establishment of Service section regarding service re-establishments at the same location. The proposed change states "For service re-establishments at the same location where the same Customer has ordered a service disconnect within the preceding twelve (12) month period, such returning Customer in addition to the service re-establishment charge, shall pay the sum of the applicable monthly Customer Charges that would have accrued had the Customer not ordered the disconnect."

Q. What is Staff's opinion on this change?

A. Staff notes that while this is a change under "Section 3, Establishment of Service" of the Company's Rules and Regulations, this issue is in conformance with "Section 2, Definitions, No. 49" which defines the Service Re-establishment Charge. Therefore Staff agrees with this change.

Q. Are there any other changes to Section 3, Establishment of Service?

A. Yes. Section 3 also establishes that "For service reconnections when due to the behavior of the Customer (i.e., nonpayment, failure to comply with the Company's Pricing Plans) it has been necessary for the Company to discontinue service utilizing other than the usual operating procedures prior to reconnection of gas service each time the gas is disconnected, in addition to the service reconnection charge set forth in the Statement of Additional Charges, the Customer shall pay the sum of the applicable monthly Customer Charges that would have accrued had the Customer not been disconnected within the preceding twelve (12) month period." This change mirrors the Service Re-establishment fee and therefore Staff agrees with this change as well.

Q. Are there any other changes of consequence proposed by the Company in the current rate case?

A. No. There are minor changes to the language employed but no substantive changes have been proposed. Staff concludes that all changes proposed by the Company be authorized.

Q. Does this conclude your direct testimony?

A. Yes, it does.

JUAN C. MANRIQUE

EXPERIENCE CHRISTENSEN & ASSOCIATES

03/08 – PRESENT *ASSOCIATE*

SCOTTSDALE, AZ

- Initiate investor relations program by meeting with new clients and deciding an appropriate goal and strategy to encourage new and further investment designed to increase share price
- Use proprietary database to target and profile potential investors
- Organize meetings between client and targets to facilitate investment
- Conduct post-meeting interviews with investors and use feedback to generate a perception study report and suggested course of action for client

RYLAND MORTGAGE

01/06 – 11/07 *MANAGEMENT TRAINEE*

DALLAS, TX

- Gained experience in all aspects of mortgage loan processing, originating and underwriting in a rotational program.
- Maintained a $7MM pipeline by interviewing buyers and originating new home loans
- Analyzed credit reports and advised most clients on strategies for improving credit score
- Received specialized training in managing groups and leading projects
- Led monthly homebuyer education courses explaining the mortgage process and different mortgage products

AMERICAN FUNDS

01/05-12/05 *SHAREHOLDER ACCOUNT REPRESENTATIVE*

SCOTTSDALE, AZ

- Successfully completed new employee training program
- Provided superior service to shareholders and financial advisers by providing quick resolutions to any and all customer inquiries
- Accurately established and maintained mutual fund accounts for thousands of new and existing clients

SHURE INCORPORATED

07/00-01/04 *Customer Service Representative* Niles,
IL

- Created new customer notification process for overnight orders
- Designed a customer service training video for new employees
- Handled all aspects of dealer orders including problem resolution
- Consistently provided high level of service to all external and internal customers by proactively anticipating their needs

Education **Arizona State University, W.P. Carey School of Business** December 2005

Bachelor of Science, Finance

Professional Skills

- Fluent in reading, writing and speaking Spanish
- Talented at organizing workload according to work priorities.
- Proficient with several software applications including Word, Excel, PowerPoint, Access, Outlook and the aptitude to quickly adapt to new ones.

BEFORE THE ARIZONA CORPORATION COMMISSION

KRISTIN K. MAYES
Chairman
GARY PIERCE
Commissioner
PAUL NEWMAN
Commissioner
SANDRA D. KENNEDY
Commissioner
BOB STUMP
Commissioner

IN THE MATTER OF THE APPLICATION OF UNS GAS, INC. FOR THE ESTABLISHMENT OF JUST AND REASONABLE RATES AND CHARGES DESIGNED TO REALIZE A REASONABLE RATE OF RETURN ON THE FAIR VALUE OF THE PROPERTIES OF UNS GAS, INC. DEVOTED TO ITS OPERATIONS THROUGHOUT THE STATE OF ARIZONA.	)	DOCKET NO. G-04204A-08-0571

DIRECT

TESTIMONY

OF

ROBERT G. GRAY

EXECUTIVE CONSULTANT III

UTILITIES DIVISION

ARIZONA CORPORATION COMMISSION

JUNE 08, 2009

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ROBERT G. GRAY RESUME RGG-1

EXECUTIVE SUMMARY
UNS GAS INC.
DOCKET NO. G-04204A-08-0571

My testimony in this proceeding addresses a number of issues related to UNS Gas, Inc.'s ("UNS") purchased gas adjustor ("PGA") mechanism. UNS has proposed to change the interest rate applicable to the PGA mechanism's bank balance. UNS has also suggested several possible proposals related to low income service that would implicate the PGA mechanism. My testimony provides Staff's analysis and recommendations regarding the PGA mechanism and related issues.

INTRODUCTION

Q. Please state your name, occupation, and business address.

A. My name is Robert G. Gray. I am an Executive Consultant III employed by the Arizona Corporation Commission ("ACC" or "Commission") in the Utilities Division ("Staff"). My business address is 1200 West Washington Street, Phoenix, Arizona 85007.

Q. Briefly describe your responsibilities as an Executive Consultant III.

A. In my capacity as an Executive Consultant III, I conduct analysis and provide recommendations to the Commission on a variety of electricity and natural gas matters. A copy of my resume is attached as Exhibit RGG-1.

Q. What is the scope of this testimony?

A. This testimony will address UNS's Purchased Gas Adjustor ("PGA") mechanism and related issues in this case.

Q. Have you reviewed the testimony of UNS Witness Kennton C. Grant in regard to the PGA mechanism?

A. Yes. I have reviewed his testimony and will discuss his proposed change to the interest rate applied to the PGA mechanism's bank balance as part of my testimony.

Q. Have you reviewed the testimony of UNS Witness D. Bentley Erdwurm in regard to the PGA mechanism?

A. Yes. I have reviewed his testimony and will discuss several ideas he has put forth regarding low income ratemaking and possible implications for the PGA mechanism as part of my testimony.

PURCHASED GAS ADJUSTOR

Q. Please discuss the functioning of the PGA mechanism in recent years.

A. At the time the currently-effective PGA mechanism was initially implemented in June 1999, natural gas prices had been relatively low and stable for a number of years. Shortly following implementation, significant changes took place in natural gas markets, leading to higher and more volatile natural gas prices which have made the last five years difficult for regulators, local distribution companies, and consumers of natural gas. Recent years have also provided a stern test of various aspects of the PGA mechanism. Staff believes that in general the PGA mechanism as currently designed and operated has worked well, given the difficult circumstances of recent years. A PGA mechanism by nature determines the manner in which commodity costs are passed through to customers, including such issues as timing and structure of such pass-throughs. In a market where the underlying commodity cost has risen from around $2.50 per mmbtu to $6.00 or so in recent years, any PGA mechanism is going to reflect those higher costs, which will be passed through to customers in some fashion, the primary variance being the manner in which the rising costs are passed along to customers.

No PGA structure can change the underlying fact that natural gas prices and price volatility have for the most part increased dramatically in recent years. Fortunately, natural gas prices as of early 2009 are the lowest they have been due to a number of factors, including growth in domestic production, weaker than expected demand, and weak economic conditions. Thus, the monthly PGA rates charged by UNS Gas and other Arizona local distribution companies ("LDC") have been trending gradually lower in recent months. However, the current low gas prices are not guaranteed to continue very far into the future and history has shown that natural gas prices can spike upward in a short time span.

In general, Staff believes that the current PGA mechanism reasonably balances the interest in shielding customers from price volatility with the competing desire to at least to some extent send a price signal to customers regarding the changing level of the underlying commodity costs.

Q. Has the Commission addressed UNS's PGA mechanism recently?

A. Yes. The PGA mechanism was considered in UNS' rate case that resulted in Decision Number 70011 (November 27, 2007). In that recent case the Commission made a number of changes to UNS' PGA mechanism, including setting the base cost of gas to zero, expanding the bandwidth on the monthly PGA rate, eliminating the bank balance threshold on undercollections, increasing the bank balance threshold on overcollections, and retaining the existing interest rate for the PGA bank balance. Staff is not proposing further change in this case to any of these matters. Staff believes that further time is needed to see how these recent changes impact the function of the PGA mechanism. Additionally, Staff has not seen any compelling evidence that further change is needed in relation to any of these issues.

Q. UNS has proposed changes to the interest rate to be applied to the PGA bank balance. Please describe UNS's proposed change.

A. UNS Witness Grant is proposing to increase the interest rate applied to the PGA bank balance by applying the 3-month London Interbank Offered Rate ("LIBOR") rate plus 1.0 percent to the PGA bank balance each month. This proposal is similar, though simpler, than UNS's proposal in the last rate case where they proposed to apply the LIBOR rate plus 1.5 percent to bank balances up to a certain size, with the portion of the balance exceeding a designated level having UNS's authorized weighted average cost of capital applied as the applicable interest rate.

Q. What was the Commission's finding regarding a UNS' similar interest rate proposal in UNS's recent rate case?

A. The Commission rejected UNS' requested increase to the interest rate. Specifically the Order states that:

> "We agree with Staff that UNS has not presented a sufficient basis for altering the PGA bank balance interest rate that currently exists. As Mr. Gray points out, a similar rate is in effect for Southwest Gas and APS, and we see no reason why UNS should be treated differently from those companies. In addition, granting a higher interest rate could provide a disincentive for the Company to reduce bank balances and could cause it to become less focused on taking all possible measures to reduce the cost of gas for its customers (Id. at 15-16). We therefore adopt Staffs recommendation to retain the current interest rate for UNS's PGA bank balances." (p.80, lines 12-18)

Q. Please discuss the history of interest being applied to PGA bank balances.

A. Until the Commission adopted the banded 12-month rolling average PGA mechanism in October 30, 1998 (Decision Number 61225), the Commission did not provide for the accrual of any interest on over- or under-recovered PGA bank balances. In Decision Number 61225, the Commission approved LDCs, including Citizens Utilities (which subsequently became UNS Gas), to begin applying interest to the PGA bank balances. The approved interest rate at that time was the monthly three month commercial non-financial paper rate, as published by the Federal Reserve. The proposal to apply this interest rate to PGA bank balances was the result of a consensus among working group participants including Staff, the Residential Utility Consumer Office ("RUCO"), Arizona LDCs, and other interested parties. Subsequently, in Decision Number 68600 (March 23, 2006) the Commission approved changing the applicable interest rate for PGA bank balances to the monthly three month commercial financial paper rate published by the Federal Reserve. The purpose for this change was that the previously approved interest rate was no longer being published by the Federal Reserve on a consistent basis, and the new rate was very similar, if slightly higher on average, than the existing rate prior to Decision Number 68600. And as previously noted, the Commission rejected changing the interest rate in Decision Number 70011 (November 27, 2007).

Q. Please discuss UNS's comparison of the 3-month LIBOR and 3-month commercial financial commercial paper rates.

A. It is unclear what LIBOR rate UNS is proposing to use in this proceeding. Mr. Grant's testimony references a 3-month LIBOR rate published by the Federal Reserve. Staff has not been able to locate a 3-month LIBOR rate on the Federal Reserve's website. Additionally, in response to Staff Data Request BG2-1, UNS provides references to the British Bankers Association ("BBA") website as well as a LIBOR rate published in the Wall Street Journal, but does not provide a reference to any Federal Reserve document or webpage. Further, the rates referenced on the BBA website and in the Wall Street Journal are set on a daily basis, and UNS has not identified how it would apply a daily rate to the monthly PGA calculations. Staff believes that use of a rate published on a monthly basis is more applicable, given that PGA accounting is done on a monthly basis. Whatever rate the Commission may apply in the future to UNS's PGA bank balance, it is important to have a clear and distinct reference point identifying the rate, to avoid any confusion regarding what interest rate is applicable.

Q. Please provide Staff's perspective on the interest rate to be applied to the PGA bank balance.

A. Staff would reiterate the points it made regarding this issue in UNS' recent rate case. Specifically, when the Commission first granted interest on the PGA bank balance in 1999, it was clear that the interest rate being adopted at that time was not equal to any LDC's expected costs of borrowing. Additionally, in rate cases since that time, the Commission has not adopted an interest rate that was considered to be equivalent to the LDC's cost of borrowing. In a recent Southwest Gas rate case (Decision Number 68487, dated February 23, 2006), the Commission adopted an interest rate for Southwest Gas, the one-year nominal Treasury constant maturities rate, that is similar to the current interest rate for UNS. Additionally, the Commission adopted the same interest rate for Southwest Gas as for Arizona Public Service. UNS has not demonstrated that it is so different from other Arizona utilities that it somehow warrants a higher interest component.

An additional aspect of this discussion is that the Company's cost of borrowing is likely to change over time, so it is unlikely that there is any simple method of setting an interest rate to specifically track UNS's exact cost of borrowing, even if the Commission wished to do so.

Also, as a general principle, to the extent an LDC receives an interest rate on the PGA balance that might be expected to fully compensate it for the costs of borrowing (or even possibly overcompensate), there could be a concern that the LDC would become less concerned with reducing the PGA bank balance and could become less focused on taking all steps necessary to reduce the cost of natural gas for its consumers.

Further, as was noted in 1999 when the Commission began allowing interest to be collected on PGA bank balances, the higher the interest rate the Commission grants for PGA bank balances, the more the resulting interest will make the PGA bank balance more volatile. The level of such additional volatility is not enormous, but the cumulative effect can be noticeable over time.

Q. What is Staff's recommendation regarding UNS's proposal to change the interest rate applied to the PGA bank balance?

A. While it is difficult to identify the specific rate or manner in which UNS would apply its proposed rate, fundamentally Staff does not believe circumstances have changed significantly since the Commission chose to retain the existing interest rate for the PGA bank balance in UNS's last general rate case order in November 2007. Staff believes that continued application of the 3-month commercial financial paper rate to UNS's PGA bank balance is reasonable and the Commission should not change to a different interest rate absent a compelling reason to do so, which UNS has not provided. Therefore Staff recommends that no change be made to the interest rate applied to the PGA bank balance.

Q. Please describe UNS' suggestions regarding low income rates and the PGA mechanism.

A. In UNS Witness D. Bentley Erdwurm's Direct Testimony he indicates the Company supports efforts to provide a discount on the commodity cost of gas to Customer Assistance Residential Energy Support ("CARES") customers and/or establish some sort of gas cost cap for CARES customers. Mr. Erdwurm further suggests that discounted amounts could be recovered through UNS's PGA mechanism. Mr. Erdwurm suggests the possibility of a working group considering these ideas, but does not provide details as to how the proposals would work.

Q. Please provide Staff's perspective on these proposals.

A. Staff is sympathetic to UNS's goal of providing greater assistance to low income customers and has worked in many rate cases over the years to improve the level of assistance provided to low income customers. However, Staff does not believe that proposals which would alter the way the PGA mechanism operates are the right venue to pursue additional low income customer relief. The Commission has always been careful to only pass through the PGA mechanism the cost of the commodity and the transportation costs to deliver the commodity as well as an interest component in recent years. For a variety of electric and natural gas utilities in Arizona, the cost of discounts provided to low income customers has either been dealt with as part of overall costs in a rate case, or passed through a separate adjustor mechanism that has been specifically designed to pass such costs through, as has been the case for Southwest Gas for many years. Introduction of low income discount costs to the PGA mechanism would unbalance the PGA mechanism, complicate the tracking of costs and recoveries through the PGA mechanism, and would tend to skew it toward developing undercollected PGA bank balances over time. If greater discounts and/or other protections are implemented for low income customers, they should be provided via means other than through the PGA mechanism. The PGA mechanism should continue, as it has in the past, to only reflect the cost of the natural gas commodity and interstate transportation costs, as well as an interest component.

SUMMARY OF RECOMMENDATIONS

Q. Please summarize your recommendations.

A. My testimony includes the following recommendations:

1. The interest rate applicable to the PGA bank balance should not be changed in this proceeding.

2. To the extent the Commission further extends rate relief to low income customers in this proceeding, the Commission should not accomplish this goal by altering the cost of gas component of rates or allowing recovery of such costs through the PGA mechanism.

Q. Does this conclude your direct testimony?

A. Yes, it does.

ROBERT G. GRAY

Education

B.A. Geography, University of Minnesota-Duluth (1988)
M.A. Geography, Arizona State University (1990) Thesis: *A Model for Optimizing the Federal Express Overnight Delivery Aircraft Network.*

Employment History

Arizona Corporation Commission, Utilities Division, Phoenix, Arizona: Executive Consultant III (November 2007 – present), Public Utility Analyst V (October 2001 – November 2007), Senior Economist (August 1997 – October 2001), Economist II (June 1991 - July 1997), Economist I (June 1990 - June 1991). Conduct economic and policy analyses on a variety of natural gas issues in Arizona, including gas procurement, rate design, interstate pipeline issues, revenue decoupling, energy conservation, low income issues, natural gas research and development funding, customer services issues, special contracts, various tariff matters, and other natural gas issues. Conduct economic and policy analyses on a variety of electricity issues in Arizona, power plant and transmission line siting cases, energy efficiency, renewable energy standards, rate design, time-of-use service, and low income issues. Prepare recommendations and present written and oral testimony before the Commission and organize workshops and other proceedings on various utility industry issues. Represent the ACC in natural gas proceedings at the Federal Energy Regulatory Commission, at the North American Energy Standards Board, and on the National Association of Regulatory Utility Commissioners' Staff Subcommittee on Gas, including serving as a past Vice-Chair and Chair of the NARUC Staff Subcommittee on Gas.

Testimony

Resource Planning for Electric Utilities, (Docket No. 0000-90-088), Arizona Corporation Commission, 1990.

Citizens Utilities Company, Electric Rate Case (Docket No. E-1032-92-073), Arizona Corporation Commission, 1993.

Resource Planning for Electric Utilities, (Docket No. 0000-93-052), Arizona Corporation Commission, 1993.

Arizona Public Service Company, Rate Settlement (Docket No. E-1345-94-120), Arizona Corporation Commission, 1994.

U S West Communications, Rate Case (Docket No. E-1051-93-183), Arizona Corporation Commission, 1995.

Citizens Utilities Company, Electric Rate Case (Docket No. E-1032-95-433), Arizona Corporation Commission, 1996.

Resource Planning for Electric Utilities (Docket No. U-000-95-506), Arizona Corporation Commission, 1996.

Southwest Gas Corporation, Natural Gas Rate Case (Docket No. U-1551-96-596), Arizona Corporation Commission, 1997.

Black Mountain Gas Company - Northern States Power Company, Merger (Docket Nos. G-03493A- 98-0017, G-01970A-98-0017), Arizona Corporation Commission, 1998.

Black Mountain Gas Company – Page Division Rate Case (Docket Nos. G-03493A-98-0695, G-03493A-98-0705), Arizona Corporation Commission, 1999.

Graham County Utilities Company Rate Case (Docket No. G-02527A-00-0378), Arizona Corporation Commission, 2000.

Black Mountain Gas Company – Cave Creek Division Rate Case (Docket No. G-03703A-00-0283), Arizona Corporation Commission, 2000.

Southwest Gas Corporation, Natural Gas Rate Case (Docket No. G-01551A-00-0309), Arizona Corporation Commission, 2000.

Black Mountain Gas Company – Page Division Rate Case (Docket Nos. G-03493A-01-0263), Arizona Corporation Commission, 2001.

Duncan Rural Services – Natural Gas Rate Case (Docket No. G-02528A-01-0561), Arizona Corporation Commission, 2001.

Toltec Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000Y-01-0112), September 2001.

Lap Paz Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000AA-01-0116), December 2001.

Bowie Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000BB-01-0118), December 2001.

Southwest Gas Corporation, Acquisition of Black Mountain Gas Company (Docket No. G-01551A-02-0425), Arizona Corporation Commission, 2002.

Wellton-Mohawk Generating Facility Application Before the Arizona Power Plant and Line Siting Committee (Docket No. L-00000Z-01-0114), February 2003.

Arizona Public Service Company, Rate Proceeding (Docket No. E-01345A-03-0437), Arizona Corporation Commission, 2004.

Graham County Utilities Company Rate Case (Docket No. G-02527A-04-0301), Arizona Corporation Commission, 2004.

Southwest Gas Corporation, Rate Proceeding (Docket No. G-01551A-04-0876), Arizona Corporation Commission, 2004.

Southern California Edison, Devers – Palo Verde 2 Transmission Line Application before the Arizona Power Plant and Line Siting Committee, (L-00000A-06-0295-00130), 2006.

Semstream Arizona Propane Acquisition of Energy West (Docket G-02696A-06-0515), Arizona Corporation Commission, 2006.

UNS Gas Inc., Rate Proceeding (Docket No. G-04204A-06-0463), Arizona Corporation Commission, 2007.

Semstream Arizona Propane Acquisition of Black Mountain Gas Company – Page Division (Docket G-03703A-06-0694), Arizona Corporation Commission, 2007.

Northern Arizona Energy, LLC, Northern Arizona Energy Project Application before the Arizona Power Plant and Line Siting Committee, (L-00000FF-07-0134-00133), 2007.

Arizona Public Service, Palo Verde Hub to North Gila 500 kV Transmission Lint Project Application before the Arizona Power Plant and Line Siting Committee, (L-00000D-07-0566-00135), 2007.

Southwest Gas Corporation, Rate Proceeding (Docket No. G-01551A-07-0504), Arizona Corporation Commission, 2008.

Arizona Solar One, LLC, Solana Generating Station and Gen-Tie Application before the Arizona Power Plant and Line Siting Committee, (L-00000GG-08-0407-00139 and L-00000GG-08-0408-00140), 2008.

Coolidge Power Corporation, Coolidge Power Project Application before the Arizona Power Plant and Line Siting Committee, (L-00000HH-08-0422-00141), 2008.

Publications

(with David Berry, Kim Clark, Lewis Gale, Barbara Keene, and Harry Sauthoff) Staff Report on Resource Planning. (Docket No. U-0000-90-088) Arizona Corporation Commission, 1990.

(with Prem Bahl) "Transmission Access Issues: Present and Future," October, 1991.

(with David Berry) Substitution of Photovoltaics for Line Extensions: Creating Consumer Choices. Arizona Corporation Commission, 1992.

(with Barbara Keene and Kim Clark) Report of the Task Force on the Feasibility of Implementing Sliding Scale Hookup Fees, December, 1992.

(with Mike Kuby) "The Hub and Network Design Problem With Stopovers and Feeders: The Case of Federal Express," Transportation Research A., Vol. 27A, 1993, pp. 1-12.

(with David Berry) Staff Guidelines on Photovoltaics Versus Line Extensions. Arizona Corporation Commission, January 28, 1993.

(with Ray Williamson, Robert Hammond, Frank Mancini, and James Arwood) The Solar Electric Option (Instead of Power Line Extension). A joint publication of the Arizona Corporation Commission and the Arizona Department of Commerce Energy Office, August, 1993.

(with David Berry, Kim Clark, Barbara Keene, Jesse Tsao, Ray Williamson, Randall Sable, Roni Washington, Wilfred Shand, and Prem Bahl) Staff Report on Resource Planning. (Docket No. U-0000-93-052) Arizona Corporation Commission, 1993.

Staff Report On Rural Local Calling Areas. (Docket No. E-1051-93-183) Arizona Corporation Commission, March, 1994.

(with David Berry, Kim Clark, Barbara Keene, Glenn Shippee, Julia Tsao, and Ray Williamson) Staff Report on Resource Planning. (Docket No. U-000-95-506) Arizona Corporation Commission, 1996.

(with Barbara Keene) "Customer Selection Issues," NRRI Quarterly Bulletin, Vol. 19, No. 1, Spring 1998, National Regulatory Research Institute.

Staff Report on Purchased Gas Adjustor Mechanisms, (Docket No. G-00000C-98-0568) Arizona Corporation Commission, October 19, 1998.

Staff Report on the Rolling Average PGA Mechanism, (Docket No. G-00000C-98-0568),Arizona Corporation Commission, September 6, 2000.

Staff Report on the Use of a Circuit-Breaker in Adjustor Mechanisms, Arizona Corporation Commission, September 3, 2003.

Staff Report on Southwest Gas Filing for Pre-Approval of Cost Recovery for Participation in the Kinder Morgan Silver Canyon Pipeline Project, (Docket No. G-01551A-04-0192), Arizona Corporation Commission, June 2, 2004.

Staff Report on Arizona Public Service Company Filing for Pre-Approval of Cost Recovery for Participation in the Kinder Morgan Silver Canyon Pipeline Project , (Docket No. E-01345A-04-0273), Arizona Corporation Commission, August 16, 2004.

Staff Report on Arizona Public Service Company Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project , (Docket No. E-01345A-05-0895), Arizona Corporation Commission, March 2, 2006.

Staff Report on Southwest Gas Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project, (Docket No. G-01551A-06-0107), Arizona Corporation Commission, May 16, 2006.

Staff Report on UNS Gas Filing for Pre-Approval of Cost Recovery for Participation in the Transwestern Pipeline Phoenix Project, (Docket No. G-04204A-06-0627), Arizona Corporation Commission, January 30, 2007.

Staff Report on Semstream Arizona Propane, Payson Division issues, Arizona Corporation Commission, June 6, 2008.

Additional Training

1990	Seminars on Regulatory Economics
1993	PURTI course on Public Utilities and the Environment
1996	Center for Public Utilities Workshop on Gas Unbundling and Retail Competition
1997	NARUC 6th Annual Natural Gas Conference
1998	Local Distribution Company Restructuring and Retail Access and Competition Conference
1998	NARUC 7th Annual Natural Gas Conference
1999 – 2007	NARUC Summer Committee Meetings
2001	Center for Public Utilities Workshop on Risk Management in Gas Purchasing
2003-2008	NARUC Winter Committee Meetings
2004-2007	NARUC Annual Convention

Memberships

NARUC – Staff Subcommittee on Gas – member, 1998 - present
NARUC - Staff Subcommittee on Gas – Vice-Chair - 2002 - 2004
NARUC - Staff Subcommittee on Gas – Chair - 2005 - 2007
Michigan State Institute for Public Utilities – NARUC Advisory Committee – 2005-2007
NARUC - North American Energy Standards Board Advisory Council – 2006 - present
NARUC – DOE LNG Partnership – 2003 - present